STATE OF ILLINOIS
ILLINOIS COMMERCE COMMISSION

Central Illinois Light Company d/b/a AmerenCILCO Proposed general increase in electric and gas delivery service rates.	))))	Docket Nos. 09-0306 09-0309
Central Illinois Public Service Company d/b/a AmerenCIPS Proposed general increase in electric and gas delivery service rates.	))))	Docket Nos. 09-0307 09-0310
Illinois Power Company d/b/a AmerenIP Proposed general increase in electric and gas delivery service rates.	)))	Docket Nos. 09-0308 09-0311

(Consolidated)

INITIAL BRIEF OF THE AMEREN ILLINOIS UTILITIES

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I. INTRODUCTION

A. Overview

The record in these consolidated proceedings establishes that the Ameren Illinois Utilities ("AIUs") are operating at a test year revenue deficiency of approximately $130 million. Staff's recommended rate increase of $44 million is approximately $86 million less than what is reasonably necessary for the AIUs to continue to provide adequate, reliable and least-cost service in the manner that ratepayers and the Commission have come to expect. If Staff's recommendations are adopted, potential actions the AIUs may need to take include deferral or cancellation of planned plant additions and replacements, as well as reduction, deferral or cancellation of other operating expenditures. These actions regrettably would in turn lead to less reliable service and reduced levels of customer service and satisfaction, all of which the AIUs would like to avoid. The consequences of these actions would inhibit the recovery of the Illinois economy and result in an overall bad deal for customers.

The AIUs' current rates were adopted in Docket 07-0585/90 (cons.) and went into effect in October 2008. These rates are no longer adequate to provide a reasonable return "on" and "of" the investment necessary to provide safe, adequate and reliable gas and electric delivery service. There are several reasons why. Foremost is the economy. The "Great Recession" of 2008-09 was one of the worse economic recessions ever -- if not <u>the</u> worst. Despite improvements in recent months, the major stock exchanges still trade lower today than they did a decade ago. Volatility, credit quality and liquidity concerns remain problematic. These and other factors have led to an inherently riskier investment environment. A riskier investment environment means that equity investors require a higher return on their investment; otherwise, they will invest in less-risky equities, or non-equity investments such as treasuries or bonds. The current investment environment directly impacts the AIUs' cost of capital. Staff's recommended rate of return, however, vastly understates the AIUs' real cost of capital. If the AIUs cannot provide an adequate return to shareholders, shareholders will invest their money somewhere else. Credit ratings will decline, borrowing costs will increase, and ratepayers ultimately will suffer higher rates. Alternatively, the AIUs will have to resort to draconian measures to keep their business viable.

The recent economic environment has had an adverse affect on the AIUs in other ways as well, initially because of the run-up in commodity prices, and later because of the ensuing market crash. For example, the AIUs endured record high fuel prices in the first half of 2008. The level of fuel expense reflected in existing rates did not come close to the AIUs' actual cost of fuel. When the stock market crashed and fuel prices dropped, the AIUs were hit on the other end with increased pension and benefits expense caused by a decrease in invested plan assets. The ensuing economic downturn led to a decrease in sales and hence, revenues. The decrease in revenues, however, was not fully offset by a decrease in operating costs, with a significant portion of the delivery costs being fixed. Despite the economic turmoil, the AIUs continued to invest in and maintain their electric and gas distribution systems. The AIUs' legal obligation to provide safe, adequate and reliable service does not have an exception for recessions.

The AIUs reacted to the recession as best they could by further enhancing existing cost-containment measures. These measures including deferring certain non-essential capital investments; deferring purchases of replacement vehicles and office furniture and equipment; deferring hiring new employees to fill vacant positions; and achieving greater economies-of-scale by purchasing certain goods and services through Ameren Services. Employees were directed to reduce their attendance at conferences, reduce non-essential training, and reduce travel expenses. Most recently, the AIUs have initiated a workforce reduction, eliminating positions in order to achieve long-term cost savings. These actions were painful, but necessary.

Despite the recent economic turmoil, the AIUs have not faltered in their prior commitments to the Commission. For example, the AIUs continue to work with Staff to implement a corrective action plan to address NESC violations. As well, the AIUs have submitted a plan to address reliability concerns noted in Liberty Consulting Group's August 2008 report of its investigation of the AIUs' preparedness for wind and ice storms. Although cost recovery for implementation of these recommendations was originally proposed in this proceeding, the AIUs subsequently determined to address cost recovery in a separate rider proceeding. Additionally, to address prior concerns about the allocation of AMS labor costs to the AIUs, 597 AMS employees have been transferred directly to the utilities. Recordkeeping problems identified in the last two rate cases have also been addressed. The AIUs have accounted for nearly all of the plant additions disallowed in the last two rate cases because of documentation issues, and Staff proposes only minimal disallowances in this proceeding. And incentive compensation plans have been structured to comply with Commission requirements for ratepayer recovery of incentive compensation expense.

There simply is no fat left to trim from the AIUs' revenue requirement request. The recommended rates of return are conservative, ranging from about 8.4% to 9.7% depending on utility. Requested pro forma plant additions have been scaled back three months to include additions only through February 2010. The requested recovery of incentive compensation expense excludes any payouts based on earnings, and payouts to the top five highest paid officers of Ameren have been excluded in their entirety. All pro forma adjustments are supported by data establishing that the adjustments are known and measurable and when the AIUs changed their budgets to reduce capital expenditures, they filed supplement direct testimony to inform Staff of this fact. The supplemental direct testimony also called to Staff's attention a final actuarial report that showed a reduction in pension and benefits expense from 2010 budgeted amounts. Indeed, during the "give and take" process of discovery, testimony and evidentiary hearings, the AIUs lowered their revenue increase request from their direct position of $226 million to their final position of $130 million.

The AIUs have made and continue to make substantial progress in providing the best possible service at the least possible cost, even under the most trying of conditions. But the positions advanced by Staff and certain Intervenors would bring this progress to a halt. The AIUs cannot continue to provide the current level of service if the cost to provide this service is not fully reflected in rates.

Staff and Intervenors use several tactics to attempt to mask the true cost of service. One of their favorites is to "normalize" expenses that they think are “too high.” Tree trimming is but one example. In the test year, the AIUs spent $39.2 million to trim trees and otherwise manage vegetation. This is about the same amount spent in 2009, based on 8 months of actual and 4 months of projected data. The 2010 budgeted expense is only slightly higher, at $39.3 million. The AIUs proposed a pro forma adjustment to establish test year tree trimming expense based on the 2010 budget. Staff, however, proposes to allow only $34.6 million in rates. Staff arrives at this position by using a historical average of tree trimming expense for the period 2005 through June 2009. The problem with Staff's approach is that historical tree trimming costs bear little resemblance to recent costs or costs that will be incurred when new rates go into effect. Staff uses a similarly-flawed approach for "normalizing" expenses for maintenance of mains, transportation fuels and working capital allowance for gas in storage. The AIUs have accepted normalization adjustments for certain costs, but only when appropriate to smooth out volatile and fluctuating items. It is not appropriate to "normalize" an expense just to artificially lower the revenue requirement for items that Staff or Intervenors subjectively think is "too high."

Another related and often-used tactic is to ignore recent data showing that historical costs do not accurately represent current costs. Pension expense is a good example. The AIUs' pension and benefits expense began to increase significantly in 2009 due to the decline is plan assets that occurred because of last year's meltdown in the financial markets. Plan assets are used to pay pension and benefits expense. When the value of plan assets decreases, pension and benefits expense increases. The AIUs therefore propose to establish test year expense based on twelve months of actual expense for the 12 months ending September 2009. This proposal is consistent with the treatment of pension and benefits expense in the AIUs’ two most recent cases, where actual expense amounts for the year following the test year was used. Staff, however, is unwilling to consider actual 2009 pension and benefits expense unless it is accompanied by a final actuarial report for 2009. Insisting on the final actuarial report is form over substance, and ignores a June 2009 valuation report that demonstrates that the AIUs’ 2009 pension and benefits expense is known, measurable and reasonable.

A third tactic is to re-write prior Commission orders to impose new standards for recovery of certain expenses. The best example of this is incentive compensation, where Staff proposes new standards for recovery of this expense. The Commission has recognized that incentive compensation plans based on the key performance indicators contained in the AIUs' plans inherently provide ratepayer benefits. These benefits need not (and as a practical matter, cannot) be financially quantified or quantifiable, as Staff contends.

Another example pertains to recovery of a sub-set of NESC corrective action expenses. The AIUs are mindful of the Commission's warning in the last rate case that "ratepayers will not be responsible for paying the costs associated with correcting distribution facilities that were initially constructed in a manner that does not comply with the NESC." Order, Docket Nos. 07-0585-0590 (cons.) (Sept. 24, 2008), p. 142. But Staff takes this language too far. In particular, Staff latches on to the above language to argue that if "the ratepayers already paid the utility for the installation," the AIUs "should not charge ratepayers a second time" to properly install the infrastructure. (ICC Staff Ex. 11.0R, p. 14, lines 323-26.) The AIUs do not disagree. That is why the AIUs have limited their rate request to the recovery of costs that ratepayers have <u>not</u> previously paid for. In the 2008 test year, the AIUs spent $13.1 million to correct NESC deficiencies. Of this amount, $8.7 million constituted "re-work" for which the AIUs do not seek recovery. But the $4.4 million spent for "new work" is properly charged to ratepayers. This work consists primarily of adding guy guards to existing guy wires, installing missing insulators and grounding ungrounded risers. Because the parts used in these installations were never installed and the work was never performed, ratepayers were never charged for the costs associated with these activities. Recovery of NESC-related “new work” installation costs is entirely consistent with the Commission’s Order in the AIUs’ prior rate case.

Contrary to Commission precedent, Staff also proposes to disallow all severance costs associated with the recent workforce reduction, not because this action doesn't produce long-term savings (it does, evidenced by Staff's adjustment to reflect these savings in the revenue requirement), but because the short-term costs necessary to produce this savings are nonrecurring. Staff also proposes to disallow all labor-related costs associated with the activities of economic development personnel, and does so despite acknowledging the essential benefits that such activities provide to the AIUs' customers.

Staff is not the only party to propose unreasonable and unsupportable adjustments or proposals. CUB proposes authorized rates that are barely above the AIUs’ cost of long-term debt and well below the next lowest authorized returns recommended in this proceeding. As well, AG/CUB and IIEC propose the very same adjustment to the AIUs’ depreciation reserve for plant in service that the Commission has, not once, not twice, and not even three times, but <u>four</u> <u>times</u> rejected. For its part, IIEC proposes to shift the true cost of service from the industrial class to all other classes through its unsupported rate design proposals.

Staff and Intervenors should not expect that if the Commission adopts their proposals, everything will be "business as usual" when new rates go into effect. The AIUs will regard the final order as a directive of where and how they should spend their money. Thus, for example, if the Commission determines that tree trimming expense should be $4.7 million less than what the AIUs spent in either 2008 or 2009 (as Staff argues), the AIUs will spend less on tree trimming. If NESC correction costs are not recoverable, the AIUs will need to consider doing this work separately (and less efficiently) from its normal circuit inspection program so that it can segregate non-recoverable NESC expense from recoverable expenses incurred during normal maintenance inspections. In short, if the AIUs cannot have reasonable assurances that all prudently incurred expenses will be recovered in rates, the AIUs will have no alternative but to synchronize their future expenditures with amounts allowed in rate orders.

The record fully supports the AIUs' requested $130 million revenue deficiency. This is the amount necessary to continue to provide safe, adequate and reliable service in a least-cost fashion. Staff's allowance of only $44 million is untenable and should be rejected. All Intervenor proposed adjustments should be rejected as well.

A. Procedural History

The procedural history in these proceedings is reflected in the Commission's E-Docket and will not be repeated at length here. Briefly stated, on June 5, 2009, Central Illinois Light Company, d/b/a AmerenCILCO ("AmerenCILCO"), Central Illinois Public Service Company d/b/a AmerenCIPS ("AmerenCIPS"), and Illinois Power Company d/b/a AmerenIP ("AmerenIP") each filed with the Commission new and/or revised tariff sheets for electric and gas service. AmerenCILCO, AmerenCIPS, and AmerenIP (collectively, the "AIUs" or "Companies") are each a wholly owned subsidiary of Ameren Corporation ("Ameren"). The new and revised tariff sheets proposed changes in electric and gas rates and the establishment of new riders. On July 8, 2009, the Commission entered six Suspension Orders suspending the Proposed Tariffs for each company to and including November 1, 2009 in accordance with Section 9-201(b) of the Public Utilities Act ("Act"), 220 ILCS 5/1-101 et seq. Upon suspension, CILCO's electric and gas filings became identified as Docket Nos. 09-0306 and 09-0309, respectively; CIPS's electric and gas filings became identified as Docket Nos. 09-0307 and 09-0310, respectively; and IP's electric and gas filings became identified as Docket Nos. 09-0308 and 09-0311, respectively. On October 7, 2009, the Commission entered Resuspension Orders renewing the suspension of the Proposed Tariffs to and including May 1, 2010. These rate proceedings advanced on the same schedule after the Commission granted AIUs' request to consolidate the dockets.

Notice of the filing of the proposed rate increases was posted in each of the AIUs' business offices and was published twice in newspapers of general circulation within each of the AIUs' service areas, in accordance with the requirements of Section 9-201(a) of the Act, and the provisions of 83 Ill. Adm. Code Part 255. In addition, the AIUs sent notice of the filing to its customers in a bill insert.

The following parties successfully petitioned the Commission to intervene: the Citizens Utility Board ("CUB"); the Grain and Feed Association of Illinois ("GFAI"); the Kroger Co. ("Kroger"); the People of the State of Illinois through the Attorney General ("AG"); the Illinois Industrial Energy Consumers ("IIEC"); the American Association of Retired People ("AARP"); Charter Communications, Inc.; System Council U-05, International Brotherhood of Electrical Workers ("IBEW"); Constellation NewEnergy-Gas Division, LLC and Constellation NewEnergy, Inc.; the Cities of Urbana, Decatur and Bloomington and Town of Normal, and the City of Champaign (the "Cities"). All testimony and evidence submitted by these parties (as well as by AIUs) is reflected on E-Docket.

On September 29, 2009, October 9, 2009, October 27, 2009 and November 2, 2009, public forums were held in Springfield, Collinsville, Pekin, and Decatur, respectively, for the purpose of receiving public comment on the AIUs' proposed general increase in electric and gas rates. These locations were selected because they represent some of the larger population centers in the AIUs' service areas. The AIUs and Staff participated, and a transcript of each public forum was made and is available on the Commission's e-Docket system.

Pursuant to due notice, status hearings were held in the matter before duly authorized Administrative Law Judges of the Commission at its offices in Springfield, Illinois on August 6, 2009 and December 10, 2009. Thereafter, evidentiary hearings were held from December 14, 2099 through December 17, 2009. The hearings were continued generally. (Tr. 904.)

B. Nature of AIUs' Operations

Ameren formed in 1997 with the merger of Union Electric Company and CIPS. Thereafter, Ameren acquired CILCO in 2002 and IP in 2004. The AIUs are comprised of AmerenCILCO, AmerenCIPS, and AmerenIP. A brief description of each of the AIUs follows.

AmerenCILCO serves approximately 210,000 electric customers over 3,700 square miles and approximately 213,000 natural gas customers over 4,500 square miles in central and east central Illinois. CILCO's service territory includes, among others, Peoria, East Peoria, Pekin, Washington, Lincoln, Morton, Tuscola and Springfield (natural gas only).

AmerenCIPS serves approximately 400,000 electric customers and approximately 190,000 natural gas customers in Illinois. The company's service territory includes, among others, Quincy, Mattoon, Carbondale, and Marion.

AmerenIP serves approximately 626,000 electric and approximately 427,000 natural gas customers across 15,000 square miles of central, east central and southern Illinois. As the largest of the AIUs, AmerenIP is responsible for 8,400 distribution miles of gas main and 40,000 circuit miles of electrical line and serves major communities such as Decatur, Belleville, Bloomington-Normal (electric only), Champaign-Urbana, Centralia, East St. Louis (gas only), Galesburg, Granite City, Hillsboro, Jacksonville, LaSalle, Maryville and Mt. Vernon.

C. Test Year

Each of the AIUs proposes a historical test year of the 12 calendar months ended December 31, 2008. No party has contested the use of this test year.

D. Legal Standard

Illinois law provides that rates for utility services "should accurately reflect the cost of delivering those services and allow utilities to recover the total costs prudently and reasonably incurred." 220 ILCS 5/1-102(a)(iv); 220 ILCS 5/16- 108(c) ("Charges for delivery services shall be cost based, and shall allow the electric utility to recover the costs of providing delivery services through its charges to its delivery service customers that use the facilities and services associated with such costs."); Citizens Utility Bd. v. Illinois Commerce Comm'n, 166 Ill. 2d 111, 121 (1995). With respect to rate design, the Commission has discretion to allocate costs that are supported by record evidence. Id. at 138. Statutorily, the Commission must favor allocating costs based on the concept of cost causation. See 220 ILCS 5/1-102(a)(iv).

The evidence submitted by AIUs in these proceedings meets the legal requirement to approve the rate requests. When a utility in a rate proceeding provides the requisite evidence relating to its prudent expenses, the burden on the opposing participants in this proceeding to successfully move for disallowance is great. Indeed, the Commission may disallow costs only if record evidence establishes *unreasonableness* or *imprudence* in the Companies' business decisions. BPI v. Illinois Commerce Comm'n, 279 Ill. App. 3d 824, 829-830 (1st Dist. 1996). As follows, many of the disallowances and adjustments proposed by certain parties in these proceedings are inappropriate.

E. Other Legal Issues

II. RATE BASE

A. Overview

The AIUs proposed a rate base for each utility. As a result of the adjustments discussed below, the proposed rate bases for the Ameren CILCO, AmerenCIPS and AmerenIP electric utilities are shown on Schedule 2 of Appendix A, B, and C, respectively. The proposed rate bases for the AmerenCILCO, AmerenCIPS and AmerenIP gas utilities are shown on Schedule 2 of Appendix D, E, and F, respectively.

B. Resolved Issues

1. Historical Plant Additions (2002-2006)

AIU witnesses Mark Livasy and Michael Getz sponsored testimony substantiating records and invoices of plant additions disallowed in the AIUs' 2006 and 2007 rate cases. (AmerenCIPS Ex. 19.0E (Livasy Dir.); Ameren Ex. 7.0E (Getz Dir.), pp. 10-12.) Mr. Livasy's direct testimony also addresses concerns raised in the 2006 and 2007 rate cases that the AIUs' recordkeeping practices violated Part 420 and Part 510 of the Commission's rules. (AmerenCIPS Ex. 19.0E, p. 8.) Staff witness Ms. Everson proposed certain adjustments to historical plant additions, (ICC Staff Ex. 2.0 (Everson Dir.), pp. 8-10), which Mr. Livasy accepted in his rebuttal testimony with certain minor corrections to Ms. Everson's calculation. (Ameren Ex. 43.0 (Livasy Reb.), p. 3; Ameren Ex. 29.0 Rev. (Stafford Reb.), p. 15; Ameren Ex. 29.7.)

2. Plant Additions (2007-2008) Except For Pana East Substation

To eliminate the plant addition sampling methodology as a contested issue in this docket, the AIUs and Staff agreed to a sampling methodology to be utilized in Staff's review of the AIUs' 2007 and 2008 plant additions. (ICC Staff Ex. 4.0 (Bridal Dir.), Attachment A.) Staff witness Bridal reviewed the 2007 and 2008 plant additions using the stipulated sampling methodology and initially identified 22 purported misstatements out of 827 transactions reviewed. (ICC Staff Ex. 4.0, pp. 4-15; Ameren Ex. 43.0 (Livasy Reb.), p. 3.) Eleven of these misstatements were subsequently rectified to Mr. Bridal's satisfaction. (Ameren Ex. 43.0, p. 4.) The AIUs also proposed additional adjustments to Mr. Bridal's adjustment relating to easement transactions and invoices with offered discounts. (Id., pp. 5-6; Ameren Ex. 29.0 Rev. (Stafford Reb.), p. 15; Ameren Ex. 29.8.) Mr. Bridal accepted the AIUs' plant addition adjustments as presented in Ameren Ex. 29.8. (ICC Staff Ex. 18.0R (Bridal Reb.), pp. 23-24.)

Staff witness Greg Rockrohr reviewed information about certain plant addition projects placed in service since the AIUs' last rate case filing and included in the AIUs' rate base in this proceeding. (ICC Staff Ex. 11.0R (Rockrohr Dir.), pp. 3-12.) AIU witness Ronald Pate discusses the AIUs' additions to plant in service included in the Companies' Schedule F-4 filings. (Ameren Ex. 6.0E Rev. (Pate Dir.).) Mr. Rockrohr initially recommended adjustments to the AIUs' rate base to remove the costs for three specific projects: AmerenCILCO's renovation of a purchased building ("Washington Street Renovation"); AmerenIP's NERC-related compliance project ("Transmission Plant"); and AmerenCIPS's relocation of the Pana East substation. (ICC Staff Ex. 11.0R, pp. 3-12.) The AIUs in rebuttal accepted Mr. Rockrohr's adjustment to remove the Transmission Plant from AmerenIP's rate base and made similar adjustments to rate base for AmerenCILCO and AmerenCIPS to remove analogous NERC-related costs. (Ameren Ex. 29.0

Rev. (Stafford Reb.), p. 38; Ameren Ex. 29.16.) The AIUs also provided Mr. Rockrohr with additional information to support their proposed allocation of costs to electric distribution customers for the contested AmerenCILCO and AmerenCIPS projects. (Ameren Ex. 33.0 Rev. (Pate Reb.), pp. 3-8; Ameren Ex. 29.0 Rev., pp. 16-18; Ameren Ex. 29.9.) Mr. Rockrohr in rebuttal accepted the AIUs' proposed allocation of costs for the AmerenCILCO Washington Street Renovation project. (ICC Staff Ex. 24.0R (Rockrohr Reb.), p. 3.) The only 2007-2008 plant addition project still contested is AmerenCIPS's project to relocate the Pana East substation. (Section II.C.3.)

3. Liberty Audit Pro Forma Adjustment

The AIUs' direct case proposed a pro forma adjustment to rate base for 2009 and 2010 expenditures associated with the implementation of certain audit recommendations of the Liberty Consulting Group. (Ameren Ex. 2.0E Rev. (Stafford Dir.), p. 24; Ameren Ex. 6.0E Rev. (Pate Dir.), pp. 48-50.) Staff recommended that this adjustment be disallowed. (ICC Staff Ex. 2.0 (Everson Dir.), pp. 10-11.) In order to reduce contested issues, the AIUs are no longer seeking recovery of 2009 and 2010 Liberty-related expenditures in this proceeding. Recovery of these expenditures instead is now being sought through a rider in Docket 09-0602.

4. Lincoln Storage Field Sulfatreat

In his direct testimony, Staff witness Seagle recommended that the Commission deny AmerenCILCO's request to recover the costs to install a fourth Sulfatreat vessel at the Lincoln storage field because it failed to adequately support the need for the installation. (ICC Staff Ex. 13.0 (Seagle Dir.), pp. 4-14.) On rebuttal, AIU witness Mr. Underwood provided additional information on the Sulfatreat vessel at the Lincoln storage field, including a net present value analysis. (Ameren Ex. 47.0 (Underwood Reb.), pp. 21-28.) Based on his review of Mr. Underwood's rebuttal testimony and accompanying exhibits, in conjunction with a site visit to the Lincoln storage field, Mr. Seagle concluded that AmerenCILCO had provided sufficient information to justify the installation of a fourth Sulfatreat vessel at AmerenCILCO's Lincoln Storage field, and the issue is resolved. (ICC Staff Ex. 26.0R (Seagle Reb.), p. 4.)

5. Materials and Supply Inventory Except for Value of Gas in Storage (C.5. below)

Staff in rebuttal testimony proposed an adjustment for both the AIUs' electric and gas utilities to reduce the Companies' Materials and Supplies Inventory (including gas in storage) ("M&S Inventory") by the amount of accounts payable associated with the purchase of materials and supplies. (ICC Staff Ex. 18.0R (Bridal Reb.), pp. 19-22.) Staff asserted that such adjustment was necessary because the AIUs' shareholders have no investment in an inventory account until the related account payable has been paid. (Id.) In order to reduce the number of contested issues, the AIUs agreed to adjustments for the General Materials and Supplies and Gas Stored Underground components of the M&S Inventory. (Ameren Ex. 51.0 2d Rev. (Stafford Sur.), pp. 14-15.) However, the AIUs continued to disagree with Staff's calculation of the portions of the AIUs' M&S Inventory in accounts payable. (Id.)

Eventually, however, Staff and AIUs agreed on a methodology for calculating the accounts payable portion of the AIUs' M&S Inventory. (ICC Staff Ex. B, December 14, 2009 Stipulation.) The parties agreed that "the General Materials and Supplies component of the total Materials and Supplies Balances will be reduced by an Accounts Payable amount calculated by multiplying the 13 month average balance of general materials and supplies by an accounts payable percentage (10.53%) based on payment lead days for the Operations and

Maintenance component of the appropriate AIU lead-lag study." (Id.) The parties further agreed that "the Gas Stored Underground component of Materials and Supplies Balances will be reduced by an Accounts Payable amount calculated by multiplying the 13 month average balance of Gas Stored Underground by an accounts payable percentage (6.63%) based on payment lead days for the PGA component of the appropriate AIU lead-lag study." (Id.)

6. Gas Tapping Fee

The Gas Tapping Fee, also known as the pro rata upfront charge for connecting with the AmerenIP gas facilities, is an $850 fee, charged to connect new home construction to the main gas line. (Ameren Ex. 3.0G Rev. (Wichmann Dir.), p. 14.) The AIUs proposed to eliminate the gas tapping fee. (Id., p. 15.) In response, Staff agreed that the fee should be eliminated, but suggested a slight adjustment to the AmerenIP Gas rate base, in order to correct the AIUs' calculations of the fee. (ICC Staff Ex. 4.0 (Bridal Dir.), pp. 30-31; ICC Staff Ex. 4, Schedule 4.15 IP-G.) Because Staff's adjustment was simply based on the AIUs' response to Staff data request RWB 6.02, the AIUs agreed to the adjustment. (Ameren Ex. 30.0 (Wichmann Reb.), p. 4.) Accordingly, this issue has been resolved.

7. Error Regarding A Sulfatreat Change Out

Staff witness Jones presented an adjustment to remove a duplicate charge associated with a Sulfatreat change out. (ICC Staff Ex. 3.0 (Jones Dir.), p. 10, Schedule 3.10.) The error was identified by the AIUs in their response to Staff data request ENG 2.08. (Id., pp. 10-11.) The AIUs do not oppose Staff's adjustment.

C. Contested Issues

1. Pro Forma Plant Additions (2009-2010)

Pursuant to 83 Ill. Admin. Code Part 287.40, the AIUs proposed a pro forma adjustment to rate base for capital plant additions to be placed into service through May 2010. (Ameren Ex. 2.0E Rev. (Stafford Dir.), pp. 21-24; Ameren Ex. 25.0 (Stafford Supp. Dir.), pp. 1-4.) Staff originally proposed to include in rate base only pro forma capital additions through August 2009. (ICC Staff Ex. 2.0 (Everson Dir.), p. 7.) Based on the rebuttal testimonies of AIU witnesses Mr. Getz (Ameren Ex. 34.0 Rev.) and Mr. Pate (Ameren Ex. 33.0 Rev.), however, Staff in rebuttal agreed to recommend allowance of known and measurable pro forma capital additions through February 2010. (ICC Staff Ex. 16.0 (Everson Reb.), pp. 2-6.) To limit the number of contested issues, the AIUs subsequently agreed with Staff's recommendation. (Ameren Ex. 51.0 2d Rev. (Stafford Sur.), p. 6.) No party previously challenged the appropriateness of the AIUs' and Staff's adjustment. Nor did any party—other than Staff—previously challenge the appropriateness of the AIUs' proposal to include certain post-test year plant additions in rate base. AG/CUB and IIEC's position that such adjustment must include an additional offsetting adjustment for accumulated depreciation is discussed immediately below in Section II.C.2.

2. Accumulated Reserve for Depreciation

The plant in service component of the AIUs' rate base reflects the historical cost of the capital assets used to provide service, less accumulated depreciation on those assets as of December 31, 2008. (Ameren Ex. 29.0 Rev. (Stafford Reb.), p. 18.) As noted above, the AIUs' rate base includes certain known and measurable post-test year pro forma capital additions, which will be placed in service by February 2010. The AIUs have included related adjustments to accumulated depreciation to reflect the additional depreciation associated with those pro forma capital additions. (Id.; Ameren Ex. 51.0 2d Rev. (Stafford Sur.), pp. 20-21.) Staff's calculation of the AIUs' accumulated depreciation and its impact on rate base reflects the same methodology used by the AIUs and repeatedly endorsed by the Commission. (ICC Staff Ex. 16.0 (Everson Reb.), Schedules 16.01; ICC Staff Ex. 15.0 (Ebrey Reb.), Schedules 15.03-15.04.)

AG/CUB and IIEC previously did not oppose a rate base adjustment to increase the AIUs' plant in service to reflect certain known and measurable pro forma capital additions. They have argued, however, that an additional adjustment to the AIUs' depreciation reserve (beyond the adjustments already made by the AIUs and Staff) is required to reflect an increase in accumulated depreciation on embedded plant (i.e., plant in service as of the end of the test year) that that will occur in the 14 month period between the end of the 2008 test year and the month ending February 2010. (IIEC Ex. 2.0-C (Gorman Dir.), p. 81; AG/CUB Ex. 2.0-C (Effron Dir.), pp. 4-6.)[1] They argue that their adjustment is supported by the Commission's pro forma adjustment rule contained in 83 Ill. Admin. Code Part 287.40 and the "matching principle."

The Commission already has rejected AG/CUB and IIEC's proposed additional adjustment to depreciation reserve—and their supporting arguments—in four prior cases. These parties provide no new evidence or arguments that warrant a different outcome here. As discussed below, the AG/CUB and IIEC adjustments violate basic ratemaking principles and the Commission's test year rules. Specifically, the proposed adjustment creates a mismatch between the utility's test year plant in service and its depreciation reserve by effectively moving

[1] Because the AIUs originally proposed pro forma adjustments through May 2010, AG/CUB and IIEC also calculated their depreciation reserve adjustments through May 2010. AG/CUB and IIEC have since acknowledged that to the extent that Staff and the AIUs have agreed to limit pro forma capital additions through February 2010, their calculations for the depreciation reserve adjustment should also be limited through February 2010. (Tr. 539 (Gorman); AG/CUB Resp. to AIU-DJE 1.16 (Ameren Group Ex. 1).)

the depreciation portion of rate base to a future period outside of the test year. This violates 83 Ill. Admin. Code Part 287.40, which provides for known and measurable "changes in plant investment" to a utility's test year plant in service, not changes in the utility's net plant or rate base at a future point in time outside of the test year. The AIUs and Staff have properly calculated the depreciation reserve in their calculation of rate base. AG/CUB and IIEC have not.

As discussed most recently in the Docket 07-0566 Order (Sept. 10, 2008), the Commission repeatedly has rejected arguments that Part 287.40 or the matching principle requires the additional depreciation reserve adjustment proposed by AG/CUB and IIEC. This adjustment was first proposed in Docket 01-0423, a ComEd rate proceeding. CGI, through testimony sponsored by Mr. Effron, argued that "[f]ailing to account for increases in post-test year growth in depreciation reserve while recognizing post-test year growth in plant . . . distorts the revenue requirements calculation." Order, Docket 01-0423 (Mar. 28, 2003), p. 43. The Commission disagreed, finding that to accept the adjustment would "improperly . . . shift the test year to the year ending on June 30, 2001, just for the accumulated depreciation reserve." Id., p. 45.

The Commission again addressed the proposed adjustment in a subsequent ComEd proceeding, Docket 05-0597. This time testifying for AG, Mr. Effron proposed to increase through the end of 2005 the entire depreciation reserve pertaining to all plant that went into service during the 2004 test year. AG argued that the adjustment was necessary to "make the pro forma balance consistent with the pro forma plant in service included in rate base, which reflects one additional year of depreciation expense on distribution and general plant." Order, Docket 05-0597 (July 26, 2006), pp. 14-15. The Commission rejected the adjustment: "The

AG's proposed adjustment does not correlate to any pro forma 2005 capital additions or any plant adjustment proposed by any of the parties. Instead, the AG's proposal merely takes one part of the rate base and moves it one additional year into the future." Id., p. 15. The Commission agreed with ComEd that "the effect of the AG's proposed adjustment would be to inappropriately bring the test year into the future for accumulated depreciation." Id.

AG/CUB and IIEC's proposed depreciation reserve adjustment was rejected for a third time in Docket 07-0241/0242 (Cons.), a rate proceeding involving North Shore Gas Company and The Peoples Gas Light and Coke Company. Mr. Effron, again sponsoring testimony on behalf of CGI, protested that "[w]hile the Utilities recognize the increase in accumulated depreciation directly related to the forecasted plant additions . . . they do not recognize the growth in accumulated depreciation on embedded plant-in-service that will be taking place as the new plant additions are going into service." Order, Docket 07-0241/0242 (Feb. 5, 2008), p. 12. Unpersuaded, the Commission found that "[i]n our view, and under our analysis, the outcome of the 05-0597 proceeding is controlling on the dispute at hand. Indeed, we are shown nothing as would have us depart from the decision that the Commission set out in that matter." Id., p. 17. The Commission reiterated that the proposed adjustment would "inappropriately bring the test year into the future for accumulated depreciation" and that "the proposed adjustment does not correlate to any pro forma capital additions or any plant adjustment proposed by any party." Id.

Not surprisingly, when presented with the depreciation reserve adjustment yet again in Docket 07-0566, the Commission "note[d] that these arguments are not novel arguments as the Commission reviewed the merits of this position in at least three cases in the recent past."

Order, Docket 07-0566 (Sept. 10, 2008), p. 28. Specifically, "[i]n the instant docket, we are asked to look at the same arguments that we considered in [Docket 07-0241/0242], Dockets 05-0597 and 01-0423 against the backdrop of consistent fact patterns." Id., p. 29. The Commission concluded that it was "not persuaded by the reconstituted arguments that the AG/CUB/IIEC proposed with regard to this issue." Id. As discussed in the Docket 07-0566 Order, AG, CUB and IIEC failed to overcome a "major concern" regarding their proposed adjustment to test year depreciation. "Namely, that the proposed adjustments do not correlate with any pro forma adjustments. 'Instead, the . . . proposal merely takes one part of the rate base and moves it one additional year into the future.'" Id., quoting Order, Docket 05-0597, p. 15.

In these consolidated proceedings, AG/CUB and IIEC again offer the same reconstituted arguments that the Commission has previously considered and rejected. Little would be served by rehashing those arguments here, as prior Commission orders on this issue are clear: adjusting the test year depreciation reserve for embedded plant in service to include post-test year depreciation on that embedded plant violates the test year and pro forma adjustment rules contained in 83 Ill. Admin. Code Parts 287.20 and 287.40.[2] As Mr. Stafford and Mr. Fiorella explain, and as the Commission has repeatedly found, AG/CUB and IIEC seek to simply bring the depreciation reserve on the entire embedded plant forward through February 2010, in effect moving one element of rate base (and only one element) to a future period while all other elements of the revenue requirement remain based on a historical period. (Ameren Ex.

[2]At hearing, IIEC's Mr. Gorman readily agreed that if his adjustment is accepted, "test year plant in service will reflect post-test year depreciation, not just on the capital additions, on all plant." (Tr. 542, line 22 - 543, line 6.)

51.0 2d Rev. (Stafford Sur.), pp. 17-18; Ameren Ex. 69.0 (Fiorella Sur.), pp. 7-8, 10, 13-14.) Indeed, Mr. Gorman acknowledges that other elements of rate base and operating income are likely to change after the test year, but his adjustment is limited to the depreciation reserve on embedded plant. (Tr. 544.) Contrary to serving the matching principle, AG/CUB and IIEC's proposed adjustment expressly violates it.

AG/CUB and IIEC's adjustments also fail to meet the known and measurable requirement set forth in 83 Ill. Admin. Code Part 287.40. As acknowledged by Mr. Gorman, there is an approximate $23 million difference between the adjustment proposed by AG/CUB and IIEC's adjustment. (Tr. 548.) While the philosophical underpinnings of these parties' positions are the same, Mr. Effron and Mr. Gorman rely on different assumptions, calculations and extrapolations, which ultimately serves only to prove that estimating the depreciation reserve as of February 2010 is not the straightforward exercise they would have the Commission believe. Where two witnesses attempt the same adjustment under the same rationale and land $23 million apart, the adjustment can hardly be said to represent a "known and measurable" change.

For their part, AG/CUB and IIEC will argue that Commission is not bound by its prior decisions, particularly given the dissenting opinion in Docket 07-0566. The dissenting opinion, however, provides no basis for a majority of this Commission to now do an about face on this issue. The dissenting opinion is largely a repackaged version of the same arguments that AG/CUB, IIEC and others have made in prior proceedings. This is evidenced by the fact that the dissenting opinion relies on IIEC and CUB's legal briefs to support its conclusions. The dissenting opinion in Docket 07-0566 offers no new evidence or new legal theories that the Commission has not previously considered (and rejected) multiple times.

Likewise, while it is one thing to say that the Commission is not strictly bound by precedent, it is quite another to say that the Commission may freely disregard precedent. The Illinois Supreme Court has recognized that "[t]he concept of public regulation includes of necessity the philosophy that the commission shall have power to deal freely with each situation as it comes before it, regardless of how it may have dealt with a similar or even the same situation in a previous proceeding." Mississippi River Fuel Corp. v. Illinois Commerce Comm'n (1953), 1 Ill. 2d 509, 513, 116 N.E.2d 394, 396-97. The Commission's discretion to decide issues on a case-by-case basis is not, however, without limitation. "While ordinarily an administrative action taken pursuant to statutory authority is entitled to great deference, an agency action that represents an abrupt departure from past practice is not entitled to the same degree of deference by a reviewing court." Commonwealth Edison Co. v. Illinois Commerce Comm'n (1989), 180 Ill. App. 3d 899, 536 N.E.2d 724, 730. As well, "administrative bodies are bound by prior custom and practice in interpreting their rules and may not arbitrarily disregard them." Alton Packaging Corp. v. Pollution Control Bd. (1986), 146 Ill. App. 3d 1090, 1094, 497 N.E.2d 864, 866 (citing various supporting authorities). The Illinois Supreme Court has similarly recognized that where the Commission determines to depart from past practice, it may not do so in an "arbitrary or capricious" manner. United Cities Gas Co. v. Illinois Commerce Comm'n (1994), 163 Ill. 2d 1, 27-28, 643 N.E.2d 719, 732. And regardless of whatever authority the Commission has to depart from prior decisions, "the Commission cannot violate the [Public Utilities] Act or its own rules." Business & Professional People for Public Interest v. Illinois Commerce Comm'n (1989), 136 Ill. 2d 192, 228, 555 N.E.2d 693,709.

Having determined in four prior cases that AG/CUB and IIEC's proposed depreciation reserve adjustment violates 83 Ill. Admin. Code Parts 287.20 and 287.40, the Commission would be hard-pressed to explain how a contrary determination in this proceeding could constitute anything other than an abrupt, arbitrary and capricious (and hence unlawful) departure from past practice. The Commission recognized as much in the Docket 07-0241/0242 (cons.) Order, where it acknowledged that "unless there are clear and distinguishable reasons for deciding a case different, the Commission will follow in line with precedent. To do otherwise risks a charge of arbitrary and capricious action." Order, Docket 07-0241/0242 (Feb. 5, 2008), p. 16.

AG/CUB and IIEC may also argue that to the extent the Commission determines to rely on prior decisions, the Commission should reach a result consistent with the Docket 02-0798/03-0008/0009 (cons.) Order. In that proceeding, which were gas rate cases by AmerenCIPS and AmerenUE, the Commission found that "where historical net plant in service is either declining or relatively static, as in these cases, post-test year pro forma increases to plant in service require further analysis." Order, Docket 02-0798/03-0008/0009 (cons.) (Oct. 22, 2003), p. 10. More specifically, "[i]n a situation where there is a demonstrated trend of significant increases of net plant in service, the Commission might be inclined to find that post test year capital additions should be reflected in rate base." Id. The Commission therefore disallowed CIPS's post-test year capital additions, but partially allowed the additions for UE "to the extent that they exceed increased accumulated depreciation." Id., p. 11.

The Commission has recognized that the circumstances in Docket 02-0798/03-0008/0009 (cons.) are distinguishable from all other cases where it has considered the depreciation reserve adjustment. Specifically, in Docket 02-0798/03-0008/0009 (cons.), the evidence showed the CIPS's net plant in service was declining or static. In Dockets 01-0423, 05-0597, 07-0241/0242 and 07-0566, the evidence showed that the utilities' net plant in service had been increasing. Here, it is undisputed that the AIUs' net plant in service has been increasing. (Tr. 549 (Gorman); Ameren Ex. 29.0 Rev. (Stafford Reb.), p. 22; Ameren Ex. 29.19.) The Docket 02-0798/03-0008/0009 (cons.) Order does not help AG/CUB or IIEC's case. See Order, Docket 05-0597 (July 26, 2006), p. 14; Order, Docket 07-0566 (Sept. 10, 2008), p. 29 (finding that the Docket 02-0798/03-0008/0009 Order does not support a depreciation reserve adjustment where net plant in service is increasing).

AG/CUB and IIEC also may suggest that the facts and circumstances of this proceeding are somehow different from Docket 07-0566 and the other prior decisions on this issue, therefore justifying a different outcome. But the relevant and controlling facts and circumstances are no different. IIEC's Mr. Gorman admits that the AIUs' accounting for depreciation on embedded plant and pro forma capital additions is functionally equivalent to the adjustments ComEd made in the Docket 07-0566 proceeding. (Tr. 545.) He also admits that his proposal to include post-test year depreciation on test year embedded plant is functionally equivalent to the adjustment he proposed in Docket 07-0566. (Tr. 546.) And in the Docket 07-0566 proceeding as here, AG/CUB and IIEC argued that 83 Ill. Admin. Code Part 287.40 and the matching principle require their adjustment. These intervening parties simply cannot "make a clear showing as to the appropriateness of such a change by way of proper evidentiary and legal support for us to consider such departures from settled precedent." Order, Docket 07-0566 (Sept. 10, 2008), p. 30.

The Commission made an observation in the Peoples/North Shore proceeding that rings equally true here: "All parties should agree that Commission action brings certainty to a situation and settles expectations." Order, Docket 07-0241/0242 (cons.) (Feb. 5, 2008), p. 16. The Commission should reject the depreciation reserve adjustments proposed by AG/CUB and IIEC, as it has consistently done in the past.

3. <u>Plant Additions (2007-2008): Pana East Substation</u>

The AIUs continue to invest in their facilities to increase system performance, meet greater customer expectations, and ensure safe, adequate and reliable service. Capital investments above a certain threshold that the AIUs seek to include in their rate base for purposes of this proceeding are described in the Companies' F-4 filing and discussed in the direct testimony of Ronald Pate (Ameren Ex. 6.0E Rev.). As noted in Section II.B.2, only one 2007-2008 plant addition project still remains a matter of dispute: AmerenCIPS's project to relocate the Pana East substation.

As discussed below, the relocation of the Pana East substation allowed AmerenCIPS to remediate coal tar contamination at the site in the most practical, cost-effective manner possible. Relocating the substation also ensured that AmerenCIPS could continue to provide service to its electric customers during the remediation. In addition, during the course of the relocation, AmerenCIPS refurbished and upgraded the substation to further improve the reliability of service and enhance service for present as well as future customers. These costs were prudent and necessary and should be included in AmerenCIPS's electric rate base.

Staff, however, proposes a rate base adjustment to exclude all capital costs, roughly $2 million, incurred by AmerenCIPS in relocating the substation. (ICC Staff Ex. 11.0R (Rockrohr Dir.), pp. 9-10; ICC Staff Ex. 24.0R (Rockrohr Reb.), pp. 3-6.) Staff proposes this rate base adjustment despite the fact that Staff does not dispute that these costs were both necessary and prudently incurred. (ICC Staff Ex. 24.0R, p. 4; Tr. 208.) Nor does Staff dispute that the relocated substation is used and useful in providing electric service. (Ameren Ex. 50.1; Tr. 209.)

Instead, Staff contests AmerenCIPS's proposed allocation of 100% of the relocation costs to electric distribution. Staff believes that these relocation costs should allocated by AmerenCIPS in an appropriate manner; Staff just does not believe that the appropriate manner is to allocate 100% of those costs to electric distribution customers. (Tr. 209-10.) Staff, however, has not proposed an alternative allocation of these relocation costs in its testimony, in response to data requests or at hearing. (Ameren Ex. 50.2; Tr. 209.) Nor has Staff presented evidence to prove that the relocation costs should be allocated in any manner other than 100% to electric distribution customers. And Staff has not adequately explained why a portion of these costs should be paid by AmerenCIPS's gas ratepayers, transmission customers, or shareholders. Indeed, Staff admits that shareholders would normally not absorb these costs. (Ameren Ex. 50.2.) Staff simply proposes to exclude from rate base all capital expenditures for this project because Staff feels that electric distribution customers should pay some lesser, undefined percentage of the costs. (ICC Staff Ex. 24.0R, pp. 4-5.)

The Commission should reject Staff's recommended exclusion of all East Pana substation relocation costs from AmerenCIPS's rate base. As explained by Mr. Pate, the relocation of the substation allowed AmerenCIPS to safely remove contaminated soil at a reasonable cost and without jeopardizing the adequacy and reliability of service. (Ameren Ex. 50.0 Rev. (Pate Sur.), pp. 3-5.) In addition, the newly relocated and rebuilt substation is used and useful in providing service to only AmerenCIPS's electric ratepayers. (Id., pp.5-7.) There is no justification to allocate a portion of the relocation costs to AmerenCIPS's gas ratepayers, transmission customers or shareholders. Nor is there any justification to disallow all capital costs for this project simply because Staff disagrees with the AIUs' proposed allocation, especially when Staff had an opportunity to propose its own allocation and refused to do so.

Staff argues that AmerenCIPS's electric distribution ratepayers should pay less than 100% of the substation relocation costs "because the cause for the costs was unrelated to the provision of electric service." (ICC Staff Ex. 24.0R, p. 5, lines 91-92.) Staff theorizes that "[i]f the contamination had originated from equipment in the substation, or was in some other way caused by the provision of electricity to customers, then it would be logical to allocate 100% of the substation relocation costs to facilitate clean-up to electric ratepayers." (Id., lines 92-94.) Staff's argument, however, is fundamentally flawed. The "cause" for the substation relocation simply does not impact the appropriate allocation and recovery of these costs. As Mr. Rockrohr recognizes, "it is appropriate to include in a utility's rate base the cost to repair or relocate distribution infrastructure, assuming it was prudent and necessary to incur those costs to maintain adequate, reliable service." (Tr. 197, line 20 – 198, line 3.)

Any number of factors unanticipated and beyond the utility's control could require a utility to repair or relocate its distribution plant. Staff admits this. (Tr. 198, 202.) Mr. Rockrohr acknowledges an extreme weather event, such a tornado or inland hurricane, could require a utility to repair damaged poles or wires. (Tr. 198.) Mr. Rockrohr acknowledges that an unexpected changing environmental condition, such as the emergence of mine subsidence or a flood plain, could require a utility to relocate existing facilities. (Tr. 198-99.) And Mr. Rockrohr concedes that in these instances it would be appropriate to charge electric ratepayers for the costs to repair and relocate infrastructure, if such actions were necessary to maintain adequate and reliable service. (Tr. 199-200.) As explained in the testimony of AIU witness Ronald Pate, the relocation of the Pana East substation not only was the least cost option and safest way to remediate the contamination, but it also presented the least risk of a disruption of service to AmerenCIPS's customers. (Ameren Ex. 50.0 Rev., pp. 3-5.)

Staff further suggests that less than 100% of the substation relocation costs should be allocated to electric ratepayers because "the contamination was caused by leakage from the utility's own manufactured gas plant." (ICC Staff Ex. 24.0R, p. 5.) That the soil contamination may have been caused by coal tar residue from a MGP once operated by AmerenCIPS, however, does not impact the allocation or recovery of the capital costs to relocate and rebuild the substation. In 1956 and 1957, when the Pana East substation was constructed, AmerenCIPS was not required to remove any coal tar present at the site. With changes to environmental laws and regulations since the 1950s, however, AmerenCIPS now is required to clean up the coal tar contamination underneath the substation. (Ameren Ex. 50.0 Rev., pp. 8-9.) And the remediation had to be accomplished in a way that did not disrupt service to customers.

Staff does not dispute that changes in legal and regulatory requirements could require a utility to relocate infrastructure. (Tr. 200-01.) And Staff agrees that it would be appropriate to recover those costs if a mandate from the governing public authority required the relocation. (Tr. 201-02.) Nor does Staff contend that AmerenCIPS should have cleaned up the coal tar in the 1950s or built the substation at a different location with the expectation that at some point in the future it might be required to clean up the coal tar. (Tr. 203-04.) AmerenCIPS should not be denied recovery of these relocation costs simply because it is now obligated to clean up this contamination 50 years after the original substation was constructed. Nor should AmerenCIPS's gas ratepayers, transmission customers or shareholders foot part of the bill.

Through false analogy, Staff suggests that AmerenCIPS would not charge its electric distribution ratepayers 100% of the costs to relocate a customer's house if the property had contamination that originated from AmerenCIPS's former MGP. (ICC Staff Ex. 24.0R, p. 5.) Staff suggests that there is no difference between the hypothetical costs associated with relocating the customer's house to facilitate cleanup and the actual costs associated with relocating the Pana East substation. (Id.) Staff's analogy, however, is misplaced. The customer house in Staff's analogy was not used and useful in providing service. (Tr. 206.) Nor did the remediation of the customer's property impair or threaten the adequacy and reliability of service. (Tr. 206-07.) Nor did the relocate customer house provide a benefit to electric ratepayers. (Tr. 207.)

Staff's position ultimately boils down to the notion that it might be appropriate to allocate some percentage of relocation costs to electric distribution customers, but not 100% of the costs; therefore, since the AIUs have proposed to allocate 100% of the costs, none of the costs should be recovered. The question left unanswered by Staff is, if allocation of 100% of the costs to electric distribution customers is not appropriate, then what is? Staff cannot rebut the AIUs' evidence that the proper allocation is 100% to electric distribution customers. Nor should Staff's proposal to disallow all of these costs be approved just because Staff disagrees with AIUs' allocation without establishing (or even offering) an alternative more appropriate allocation. The Commission therefore should reject Staff's proposal to disallow these costs.

4. Hillsboro Storage Field – Used and Useful

In 1993, AmerenIP expanded its Hillsboro storage field. The Commission approved the expansion and concluded that Hillsboro would "provide substantial net economic and other benefits to IP's customers" and it "should be considered used and useful" when placed into operation. (ICC Staff Ex. 12.0 (Lounsberry Dir.), p. 23, lines 466-71, citing Order, Docket No. 93-0183 (April 6, 1994), p. 8.) AmerenIP intended the expansion to increase the field's total storage and peak day storage withdrawal capability. (Id., pp. 23-24, citing Order, Docket No. 91-0499 (Oct. 21, 1992), p. 3.) AmerenIP estimated that, after expansion, the storage field would contain 21.7 Billion cubic feet ("Bcf") gas-in-place, including 7.6 Bcf inventory gas and 14.1 Bcf base gas. (Id., p. 24)

Since the 1993 estimates, however, with the exception of the 1993-94 season, Hillsboro has not operated at or near 7.6 Bcf. And AmerenIP, using newly-available technology to update its understanding of the Hillsboro storage field and its capacity, has determined that geological conditions at Hillsboro likely prevent the field from operating at design capacity. (Ameren Ex. 47.0 (Underwood Reb.), p. 7.) Staff fails to consider this new information, which was identified by far more advanced computer modeling than what was previously available. Based on this new information, AmerenIP deems it prudent to cycle the field at 6.4 Bcf, rather than the 1993-estimated design capacity of 7.6 Bcf. Indeed, Staff agrees Hillsboro should be cycled at 6.4 Bcf (ICC Staff Ex. 25.0, p. 24), but claims that Hillsboro is not 100% used and useful because it is not currently cycling at 1993 estimated levels. (ICC Staff Ex. 12.0, pp. 17-18.) Instead, Staff witness

Mr. Lounsberry calculates Hillsboro is 96.01% used and useful and thus proposes a used and useful disallowance. (Id., Schedule 12.01.)

Staff's recommended used and useful disallowance is flawed and must be rejected for four reasons: (1) Staff incorrectly relies on the 1993 design capacity estimate of Hillsboro and does not recognize the importance of new information, based on previously unavailable and more advanced computer modeling, regarding Hillsboro's geology; (2) Staff concedes that the Hillsboro storage field should cycle 6.4 Bcf for the next several years; (3) Staff overlooks the fact that Hillsboro substantially benefits customers; and (4) Staff wrongly connects its used and useful adjustment to past operational concerns at Hillsboro. But even if the Staff's proposed disallowance was not flawed for these reasons, the Commission should not impose a disallowance where Staff's calculation of the field's used and usefulness is so near 100%.

a. *Staff's used and useful calculation incorrectly relies on the 1993 design capacity of Hillsboro.*

In Illinois, "[a] generation or production facility is used and useful only if, and only to the extent that, it is necessary to meet customer demand or economically beneficial in meeting such demand." 220 ILCS 5/9-212. In determining whether a facility is used and useful, the Commission considers the extent to which a plant is needed to meet the utility's projected demand and whether the plant provides net economic benefits to ratepayers. Order, Docket Nos. 87-0427 *et al.* (cons.), 1993 Ill. PUC LEXIS 84, *77-80 (Feb. 24, 1993); Order, Docket No. 94-0065, 1995 Ill. PUC LEXIS 25, *16-18 (Jan. 9, 1995).

The Commission recognizes, however, that capacities estimated during the design and construction phases may differ from actual operational capacity, and thus, has rejected reliance on design capacity in determining used and usefulness. Order, Docket No. 89-0276, 1990 Ill.

PUC LEXIS 313, *156-62 (June 6, 1990). For example, where a utility assigned a "nominal" capacity during design and construction of a plant as an approximate capability value, the Commission stated "it was not possible to determine precisely what the net output of the plant would be during its design and construction states, until it was completed, placed in service and tested." Id., pp. *161-62. Thus, use of a "nominal" value for projected capability during design and construction of the plant was not a basis on which to establish the used and usefulness of a plant. Id. Likewise, where capacity is restricted or not available due to physical constraints, such capacity should not be included in a plant's total effective capacity for purposes of determining used and usefulness. Order, Docket Nos. 87-042, at *89-91.

To demonstrate that Hillsboro is not currently operating in "the same manner" as was originally predicted, Mr. Lounsberry cites the Commission's 1992 order granting Illinois Power a certificate for Hillsboro (Docket No. 91-0499) entered before Hillsboro's expansion was complete. In that Order, the Commission stated that "[e]stimated gas-in-place after the Hillsboro Storage Field expansion will be 21.7 Bcf, consisting of 7.6 Bcf of inventory gas and 14.1 Bcf of base gas." (ICC Staff Ex. 12.0, pp. 23-24.) Mr. Lounsberry faults AmerenIP because Hillsboro has not operated at those levels since expansion. (Id., p. 24.) But it is Mr. Lounsberry's reliance on design estimates of capacity that is faulty.

Despite the fact that AmerenIP predicted a design cycling capacity of 7.6 Bcf in 1993 for Hillsboro, the field's actual operating conditions are inconsistent with that design capacity. As Staff witness Mr. Lounsberry concedes, Hillsboro has not operated at 7.6 Bcf since 1993. (Tr. 161-62.) And AmerenIP recently has been able to identify physical, capacity-limiting characteristics of the Hillsboro field by applying new technology – not yet developed in 1993 – and conducting a detailed study of Hillsboro (the "Hillsboro Study").

The Hillsboro Study employed several improved and independent engineering methods, including a reservoir simulation study and a hysteresis curve evaluation.[3] (Ameren Ex. 47.0, pp. 7-8.) With the use of these new, more advanced technologies, the Hillsboro Study identified a geological condition by which gas migrates to a less accessible region of the field. Significant volumes of gas migrate from the St. Peter formation – which is located near the well bore that cycles gas from the field – into the Joachim cap rock porosity – which is not accessible to that bore. (Id., pp. 12-13.) The porosity of the Joachim formation traps the gas, causing a shortfall of gas to be cycled. (Id., pp. 13-14.) This materially affects the field's performance relative to its design capacity: while the 1993 reservoir analysis expected the entire 21.7 Bcf of gas injected into the reservoir at the end of expansion to exist in the St. Peter formation, the Hillsboro Study revealed that approximately 3.5 Bcf of gas has since migrated from the St. Peter formation into the Joachim cap rock porosity. (Id.) The Study indicated the St. Peter formation cycles only 5.8 Bcf of working gas, while the Joachim porosity cycles 0.6 Bcf. (Id., p. 13.) Thus, the Hillsboro Study demonstrated that the best current estimate of working gas capacity is 6.4 Bcf. (Id.)

The volume currently and prudently cycled at Hillsboro, and not the estimated volume, should determine the used and usefulness of the field. The Commission has determined that "the used and useful calculation should be based on the Company's existing capacity

[3] A hysteresis curve is a plot of the gas pressure in the storage field versus the field inventory, which can be used to verify the inventory within the field and to monitor their underground storage reservoir's performance. (Ameren Ex. 47.0, pp. 8-9.)

configuration," which the Commission terms "actual capacity." Order, Docket Nos. 87-0427, at *90. It is simply not appropriate for Staff to base its used and useful calculation on design, as opposed to actual, capacity. Rather, the Commission's used and useful assessment should consider the current effective capacity of the Hillsboro storage field. (Ameren Ex. 47.0, p. 15.)

Moreover, modifying the amount of working gas cycled is not unusual. Underground storage reservoirs are very complex/heterogeneous geological formations, and as a result, these reservoirs are difficult to fully understand because there are multiple variables that can change and many variables that cannot be discretely measured but must be interpreted. (Ameren Ex. 47.0, p. 7.) Volumes are commonly adjusted based on the field's actual operating experience and recently updated information. (Id., p. 9.) Other companies have similarly adjusted working volumes without a disallowance or other penalty. (Id.) Indeed, Mr. Lounsberry concedes that storage fields "have adjusted their volumes in the past." (ICC Staff Ex. 25.0 (Lounsberry Reb.), p. 19.)

However, these prior examples are relevant and applicable to this proceeding. For example, in Docket 90-0127, the Commission approved a working gas inventory adjustment but did not make a used and useful disallowance. (Ameren Ex. 47.0, p. 9.) In addition, in Docket 07-0585-07-0590, a working gas inventory adjustment was made at Sciota field without a used and useful disallowance. In that case, like here, studies indicated the need to adjust working and base gas. (Id.)

The Commission has recognized that capacity cannot be exactly determined before a field operates. This is clearly the case at Hillsboro, especially given that geological conditions limiting capacity now have been identified with technology not yet available before its post-expansion operations. Thus, Staff's used and useful calculation based on original design capacity is a flawed method and should be rejected.

b. *Staff concedes that Hillsboro should cycle 6.4 Bcf for the next several years, and thus, AmerenIP should not be penalized.*

Mr. Lounsberry concedes that, "AmerenIP needs to maintain the operation of the Hillsboro storage field in a consistent manner, the 6.4 Bcf level, to allow AmerenIP to determine the operating characteristics of the Hillsboro storage field." (ICC Staff Ex. 25.0, p. 22, lines 433-36.) However, he also asserts that, "AmerenIP cannot make any changes to the Hillsboro storage field specifications it (sic) until it has operated the field in a certain manner because it still does not know what those specifications are even though the field expansion took place 16 years ago." (Id., pp. 22-23, lines 436-39.) This mischaracterizes AmerenIP's position on inventory revisions at Hillsboro. (Ameren Ex. 63.0 (Underwood Sur.), p. 12.) The Hillsboro Study does not state that AmerenIP needs to cycle the field in a consistent manner or cannot make changes to the field specifications. (Id.) Rather, the Study recommends that 6.4 Bcf of gas be cycled from the field for the next several years and that verifications studies be performed. (Id.) Moreover, the Study asserts that the annual cycling of 6.4 Bcf will help the reservoir stabilize further, increasing the accuracy and validity of the reservoir engineering studies. (Id.)

AmerenIP plans to consistently operate the field at 6.4 Bcf over the next few years to conduct reservoir engineering studies. (Ameren Ex. 47.0, pp. 8-14.) Mr. Lounsberry does not disagree with AmerenIP's logic on seeking to operate the field at 6.4 Bcf and agrees that maintaining the field at a consistent level will allow AmerenIP to better determine the operating characteristics of the field. (ICC Staff Ex. 25.0, pp. 22, 24.) He also concedes

AmerenIP has new data that shows ongoing migration into the cap rock. (Id., p. 27.) Thereby, Staff acknowledges that Hillsboro may not be able to operate at its design capacity. (Ameren Ex. 63.0, p. 7.)

Ameren should not be penalized for operating Hillsboro in a prudent manner, especially in light of new information suggesting the field may not geologically be able to operate at its initial design capacity. (Id., p. 11.) By proposing to penalize the utility, Mr. Lounsberry disregards his assertion that it is appropriate to operate Hillsboro at 6.4 Bcf. (Id.)

c. *Hillsboro provides substantial benefits to customers.*

AmerenIP invested over $154 million to expand Hillsboro in 1993. This investment benefits customers by allowing the Company to purchase and inject gas when less costly in the summer and withdrawing it in winter; it also increases peak day deliverability. (Ameren Ex. 63.0, p. 4.) Customers' savings for the first year were estimated at $14,596,500, and Mr. Lounsberry does not dispute that these benefits have been, and continue to be, realized. (Id.) In addition, since it is unclear whether Hillsboro is able to operate at 7.6 Bcf, it is unclear whether extra ratepayer benefits, to which Mr. Lounsberry refers, are achievable. (Id., p. 14.) Until operational parameters are further defined, it is imprudent to risk the additional 1.2 Bcf of gas costs. (Id.)

That Hillsboro is operated below 7.6 Bcf is a result of the field's physical properties, and not due to any imprudent actions by AmerenIP. (Ameren Ex. 63.0, p. 4.) By maximizing the inherent characteristics of the field, AmerenIP operates the field to maximize benefits to customers. (Id.) Mr. Lounsberry agrees: he does not assert that AmerenIP's scheduling of 6.4 Bcf is imprudent. (Id., pp. 4-5.) And, importantly, he admits that it may be imprudent to operate a storage field in a manner to achieve a specific capacity. (Tr. 162-63.) In the meantime, Hillsboro more than offsets the amounts customers would have paid without having the benefit of Hillsboro. (Ameren Ex. 47.0, p. 17.) Thus, Hillsboro is necessary to meet customer demand and it is economically beneficial in meeting such demand, and so should be considered used and useful. 220 ILCS 5/9-212.

d. *Staff's attempts to link its used and useful analysis to Hillsboro concerns should be disregarded.*

Mr. Lounsberry asserts that his used and useful proposal relates to past operational issues at the Hillsboro storage field. (ICC Staff Ex. 12.0, pp. 20-22.) He argues that, due to inventory corrections at Hillsboro, AmerenIP could not conduct inventory verification studies and now must operate the field consistently to determine its current operating parameters. (Ameren Exs. 63.0, pp. 18-19) Regardless of what transpired in the past, however, AmerenIP could only now identify the geological limitations to the field's capacity because the necessary technology was not previously available. (Id.) Mr. Lounsberry agrees that information now known differs from the facts of Docket No. 04-0476, and he further concedes that AmerenIP addressed prior events that impacted Hillsboro's inventory volumes. (Ameren Ex. 63.0, p. 6; ICC Staff Ex. 12.0, p. 22.; 25.0, p. 19) In fact, he acknowledges Ameren's improvements at Hillsboro, including that "Ameren was able to return the Hillsboro storage field to its full peak day capacity value and approach the seasonal withdrawal capacity value . . . ." (ICC Staff Ex. 12.0, p. 25, lines 504-05.)

Moreover, the facts of prior Hillsboro proceedings are distinguishable from facts here. In Docket No. 04-0476, Staff considered volume histories to reduce withdrawal volumes, but here, Staff considers working volumes by relying on scheduled withdrawal volumes. (Ameren

Ex. 47, p. 6.) Also, previously, metering errors caused volumes reductions, while here, working volumes are reduced at Hillsboro because of geological conditions. (Id.)

Finally, Mr. Lounsberry argues that the use of a hysteresis curve is compromised because of past issues at Hillsboro. (ICC Staff Ex. 25.0, pp. 23-25.) Yet, he overlooks that the hysteresis curve, which indicates only whether (not why) an inventory issue may exist, is only a part of the Hillsboro analyses, as discussed above. (Ameren Ex. 63.0, p. 16.)

e. *Because Staff's used and usefulness calculation for Hillsboro is very near to 100%, a disallowance is not appropriate.*

The Commission should reject Mr. Lounsberry's "suggestion" for a ruling to "ensur[e] AmerenIP is aware of the Commission's concerns with the operation of its Hillsboro storage field . . . ." (ICC Staff Ex. 12.0, p. 33, lines 667-69.) AmerenIP believes such a ruling – which necessarily would not be grounded in the evidence offered in this proceeding – would be improperly punitive. (Ameren Ex. 47.0, p. 21.) AmerenIP encourages the Commission to rule on the evidence presented to determine whether the costs associated with Hillsboro were prudently incurred. (Id.)

Both Mr. Lounsberry and AmerenIP recognize the peculiarity of Mr. Lounsberry's recommended disallowance: Mr. Lounsberry's used and useful calculation of 96.01% is "very near a finding of 100% used and useful." (ICC Staff Ex. 12.0, p. 32, line 640.) Thus, Mr. Lounsberry requests that the Commission address whether there is a used and usefulness amount that "essentially negates the need to recommend a used and useful disallowance." (Id., lines 641-42.)

A disallowance in such a close case is inappropriate, especially given that gas storage operations can be unpredictable. (Ameren Ex. 47.0, p. 19.) If a field is operated prudently based on the information currently available, AmerenIP maintains that a disallowance is not appropriate when new information suggests the utility should change its operations. (Id., p. 13.) Moreover, "customers still have benefited far more by having the Hillsboro asset than not having the asset." (Id., lines 288-89.) Given the prudent operation of Hillsboro, and benefits enjoyed by customers, AmerenIP asserts that a disallowance based on a 96.01% used and useful calculation is poor policy.

In conclusion, Hillsboro is operating to meet current customer demand and provides net economic benefits to ratepayers. Therefore, it is 100% used and useful.

5. Cash Working Capital

A Cash Working Capital ("CWC") requirement is the amount of funds required to finance the day-to-day operations of a utility. (Ameren Ex. 4.0E (Heintz Dir.), p. 3) A positive CWC requirement indicates that the utility's shareholders are providing funds associated with the payment of expenses prior to the collection of revenues from the AIUs customers. A negative CWC requirement indicates that the utility's customers are providing funds via the collection of revenues prior to the payment of expenses. The CWC requirement is calculated by conducting a lead-lag study, which examines the timing of cash flows – both revenues and expenses.

The AIUs filed the testimony of David Heintz supporting a CWC requirement of $6.3 million, $4.1 million and $10.6 million for AmerenCILCO's, AmerenCIPS's and AmerenIP's gas operations, respectively and $0.5 million, $2.2 million and $(1.1) million for AmerenCILCO's, AmerenCIPS's and AmerenIP's electric operations, respectively, based upon an historical test year for the twelve months ended December 31, 2008. (Ameren Exs. 4.1-4.6.) The methods employed to determine the CWC requirement for the gas and electric businesses of each of the

AIUs were consistent with the Commission's decisions in the AIUs' prior rate case proceedings, Docket No. 07-0585 et. al (cons.). Ameren Ex. 4.0E, p.3)

Staff identified four potential issues with the AIUs' CWC analyses:

1. Use of the Gross Lag Methodology versus the Net Lag Methodology;
2. Use of consistent expense lead days for Other Operations and Maintenance ("O&M") expenses for both the gas and electric businesses;
3. Use of a revenue lag of zero days for pass-through taxes; and
4. The inclusion of service lead time in the expense lead days for pass-through taxes.

(ICC Staff Ex. 1.0 (Ebrey Dir.), p. 19.)

In its rebuttal testimony, Staff accepted the AIUs presentation of bank facility fees and the expense lead time for those fees as presented in the Company testimony and exhibits. (ICC Staff Ex. 15.0, (Ebrey Reb.), p. 13.)

In all other respects, Staff adopted the AIUs' CWC analyses. In their rebuttal testimony, the AIUs accepted Staff's proposed use of the Gross Lag Methodology to calculate the CWC requirements and the use of a consistent expense lead for Other O&M expenses for both the gas and electric businesses. (Ameren Ex. 31.0 (Heintz Reb.), pp. 2-3.)

The AIUs and Staff agree that the level of CWC allowed should be based upon the final level of cash expenses approved by the Commission in these proceedings. (ICC Staff Ex. 15.0, p. 13.)

The IIEC submitted direct testimony proposing a collection lag of 21 days. (IIEC Ex. 3.0 (Meyer Dir.), pp. 4-5.) In its rebuttal testimony, the IIEC also argues that uncollectibles should have been excluded from the calculation of the collection lag. (IIEC Ex. 7.0 (Meyer Reb.), p. 7.)

a. *Revenue Lag for Pass-Through Taxes*

The AIUs applied a revenue lag to all revenues, with the exception of those associated with pass-through taxes, which consisted of a service lag, a billing lag, a collection lag, a payment processing lag and a bank float lag. (Ameren Ex. 4.0E (Heintz Dir.), pp. 7-8.) Because Staff has taken the position in prior rate proceedings that pass-through taxes are not associated with the provisioning of a service, the AIUs excluded the service lag from the revenue lag that was applied to the pass-through taxes. (Id., p. 120) The service lag excluded from the revenue lag attributed to pass-through taxes was 15.21 days (i.e., 365 days divided by 12 months divided by 2 to reflect the midpoint of the month). (Id., p. 9.)

The AIUs' position reflects the reality that whether or not a service is provided, the Companies still must bill, collect and process the revenues associated with the pass-through taxes. (Ameren Ex. 53.0 (Heintz Sur.), p. 3.) The AIUs' customers make only one monthly payment which includes both the amounts associated with monthly services received and the pass-through taxes. No other vehicle exists by which the customers make payment.

Unlike arguments presented in prior cases, Staff this time argues that a revenue lag of zero days should be applied to pass-through taxes. (ICC Staff Ex. 1.0 (Ebrey Dir.), p. 21.) Staff contends that there is no lag between a delivery of utility service and the receipt of cash in regard to pass-through taxes, and, thus, there is no lag. (Id., p. 22) Staff is incorrect. In fact, Staff's position ignores the very purpose of the CWC analyses, which is to examine the timing of cash flows. (Ameren Ex. 53.0 (Heintz Sur.), p. 4.) Staff ignores the timing of the collection of revenues associated with pass-through taxes. Further, as discussed later, Staff proposes a completely contradictory position with regard to the treatment of the expense side of the pass-through taxes. (Id.)

The infirmity of Staff's position regarding the treatment of pass-through in the CWC analyses is best shown in Ameren Exhibit 31.1. This exhibit, which uses Electric Gross Receipt Taxes as an example, compares the AIUs' and Staff's positions regarding the timing of receipt of revenues for and the payment of pass-through taxes. The exhibit demonstrates that the AIUs remit payment associated with pass-through taxes after 27.53 days while the customers' payment for such taxes is not received for 31.34 days. Therefore, the AIUs are remitting payment for pass-through taxes 3.81 days prior to the receipt of payment from their customers. (Ameren Ex. 31.0 (Heintz Reb.), pp. 7-8.)

Staff, on the other hand, claims that payment of the pass-through taxes occurs after 42.8 days and that the revenues are in hand for the AIUs use immediately. Staff offers no explanation (nor can they) as to how the AIUs collect the funds associated with the pass-through taxes, if not via the customer's monthly payment. Staff's position does not reflect the actual timing of cash receipts and cash payments with regards to pass-through taxes.

In support of its position, Staff's rebuttal testimony stated as follows:

> The information on the table does not in fact compare the date that funds are received with the date that funds are remitted to the taxing authorities. The 31.34 day revenue lag is a measurement from the point that a bill is initiated until the funds are available to the Company and includes factors for Billing, Collections, Payment Processing, and Bank Float. This measures various factors related to the receipt of revenue but does not identify the date that the funds are actually received. The various expense leads measure the tax period ending date with the date that the funds are removed from the Company's bank account and include factors related to tax periods and tax due dates but do not identify the date that the funds are actually remitted.

(ICC Staff Ex. 15.0 (Ebrey Reb.), pp. 14-15.)

Staff is correct that the AIUs revenue lag for pass-through taxes includes factors for Billing, Collections, Payment Processing and Bank Float and that the expense lead measures the tax period ending date with the date that the funds are removed from the Company's bank account. These are precisely the factors which should be measured when conducting a CWC analyses. Staff's assertion that the Companies' factors do not identify the date that funds are actually received or remitted is incorrect. The CWC analyses, which Staff adopts in all respects other than the pass-through taxes, are based exclusively on actual receipt and payment dates. (Ameren Ex. 53.0 (Heinz Sur.), p. 4.)

The Commission should reject Staff's proposed zero days revenue lag attributed to pass-through taxes in favor of the 31.32 revenue lag supported by the AIUs. The Companies' revenue lag reflects the overall revenue lag of 46.53 days less the 15.21 service lag. No evidence or analyses have been presented by Staff to demonstrate how the revenues associated with the pass-through taxes are available immediately to the AIUs. The customers' payment of the monthly bill is the only source by which the AIUs receive payment for the pass-through taxes. The AIUs' CWC analyses accurately reflects the timing of the billing, collection, processing and bank float associated with the customers' payments during the test year.

b. *Inclusion of Service Lead Time in the Expense Lead Days for Pass-through Taxes*

Consistent with its proposed treatment of the service lag, the AIUs excluded the service lead from the overall expense lead associated with the pass-through taxes. The AIUs' position is simple – if there is no service period, it should not be applied to either the revenue lag or the expense lead.

Despite its position that the service lag was correctly excluded by the AIUs when calculating the revenue lag applied to pass-through taxes, Staff has proposed that the service lead continue to be included in the overall expense lead. Clearly Staff's position to exclude the service lag but include a service lead is a results-oriented attempt to lower the AIUs CWC allowance.

Staff contends that the amounts related to pass-through taxes accrue over a monthly or quarterly period and are remitted, in most cases, after the end of the accrual period and that a service lead is necessary to accurately reflect the lead time. (ICC Staff Ex. 1.0 (Ebrey Dir.), p. 23.) As previously stated, the AIUs CWC analyses reflect the actual timing of the payment of the pass-through taxes. No service lead is necessary to address anything related to accruals and remittance timing differences. (Ameren Ex. 31.0 (Heintz Reb.), pp.3-5.)

The service period is associated with the timing of the provisioning of service. Staff has previously argued that there is no service period associated with pass-through taxes. Staff's new position is that there is no service lag associated with the collection of the revenues associated with pass-through taxes, but that there is a service lead associated with the payment of the pass-through taxes. Either there is a service period or there is not.

Staff's position regarding the inclusion of a service lead of 15.21 days to the overall expense lead should be rejected. The inclusion of a service period is unsupported and inconsistently applied by Staff. The AIUs accurately and consistently exclude the 15.21 days from both the revenue lag and the expenses lead.

c. *IIEC's Proposed Collection Lag*

Section 280.90 of the Commission's rules gives residential customers 21 calendar days from the issuance of the monthly bill to pay the bill before late charges may be assessed. 83 Ill. Admin. Code 280.90. The AIUs' CWC analyses reflect the reality that, while many of their customers pay their utility bills in full and on time, there are customers who are delinquent in the payment of their bills. The AIUs calculated a collection lag of 28.13 days, based upon an analysis of the aging of accounts receivables during the test year. (Ameren Ex. 4.0E (Heintz Dir.), pp. 8-9.) Staff did not oppose this collection lag.

IIEC proposes that the collection lag included in the overall revenue lag should be capped at the number of days allotted for the AIUs residential customers to pay their bills from the issuance of the monthly bill. (IIEC Ex. 3.0 (Meyer Dir.), p. 6.) IIEC provides no support for the reasonableness of its position. Nor has IIEC offered specific suggestions for improvements in collection activities that the AIUs should implement. Further, IIEC has not identified any other companies which had a collection lag limited to the statutory time afforded a customer to pay their bill. The fact that customers are supposed to pay their bill within 21 days doesn't mean they do.

The AIUs collection compares favorably to that of other regulated utilities in the State of Illinois. The approved collection lag for Nicor was 33.77 days. (Ameren Ex. 31.0 (Heintz Reb.), p. 10.) Peoples Gas Light and Coke and North Shore Gas Company filed a collections lag of 32.72 days. (Id.) The MidAmerican Energy Company has filed a collection lag of 25.68 days. (Id.)

In an attempt to support its recommendation, in its rebuttal testimony the IIEC alleges that the AIUs have overstated its collection lag because uncollectible expenses were not excluded from the analyses. (IIEC Ex. 7.0 (Meyer Reb.), p. 6.) While disagreeing with the IIEC as to whether uncollectible expenses need to be excluded from the CWC analyses, the AIUs performed a recalculation of the collection lag excluding the uncollectible expenses. The exclusion of uncollectible expenses from the collection lag had no impact on the overall analysis. (Ameren Ex. 53.0 (Heinz Sur.), p. 8.)

The IIEC's proposed collection lag has no basis in reality and should be rejected. The AIUs' collection lag compares favorably to those of other regulated utilities in the State of Illinois. While all wish that all customers pay their monthly bills in full and by the due date, such a position is just that - wishful thinking. The collection lag which has been presented by the AIUs and supported by Staff should be adopted by the Commission.

6. <u>Working Capital Allowance for Gas In Storage</u>

Staff, in direct testimony, questioned the AIUs' pricing calculation for the working capital allowance for gas in storage.[4] Staff witness Lounsberry asserted that "Ameren's reliance on 2008 gas costs to value its requested working capital allowance for gas in storage amount results in an overstatement of the costs due to the reduction in natural gas prices since 2008." (ICC Staff Ex. 12.0 (Lounsberry Dir.), p. 3, lines 40-42.) He therefore recommended that

[4] Staff and the AIUs agree to the appropriate volume of gas to reflect in the computation of the working capital allowance for gas in storage. Staff proposed certain adjustments to the volume of gas in storage based on expiring leased storage contracts and other concerns. (ICC Staff Ex. 12.0 (Lounsberry Dir.), pp. 7-17.) The AIUs adjusted volumes to reflect storage contracts that will not be renewed or where the volumes of gas under contract had increased or decreased, revised volumes of leased storage services for the Sciota storage field, and addressed concerns regarding storage fields or contracts no longer in service and the Texas Gas leased storage service. (Ameren Ex. 65.0 (Seckler Sur.), p. 5.) These adjustments and explanations addressed Staff's concerns. (ICC Staff Ex. 25.0 (Lounsberry Reb.), pp. 6-7.)

“Ameren provide in its rebuttal testimony an updated calculation [for its working capital allowance for gas in storage] that follows the same pricing methodology that Ameren proposed and was accepted by the Commission in Ameren’s last rate case.” (Id., p. 4, lines 76-79.) Specifically, he recommends that, “Ameren should revalue its requested amounts by using the actual pricing data from 2009.” (Id., lines 79-80.)

While it is appropriate to reflect updated information on gas in storage pricing, the AIUs oppose Staff’s proposal to use 2009 gas pricing to determine the value of the AIUs’ gas in storage. (Ameren Ex. 45.0 Rev. (Seckler Reb.), p. 8.) Staff’s proposal does not take into account the changed circumstances that the AIUs are experiencing with respect to gas prices since the prior case. Instead, the AIUs propose to value their gas in storage for the purposes of the working capital calculation using a three year average of prices through December 2009. This methodology accounts for variation in gas prices by using an average and addresses Mr. Lounsberry’s concern about using more recent gas prices by reflecting gas prices through December 2009. (Id., p. 8, 9; Ameren Ex. 45.1.)

As Mr. Lounsberry acknowledges, the price of gas has declined since 2008. (ICC Staff Ex. 12.0, p. 4.) In fact, the price of gas has exhibited significant variability since the AIUs’ last rate cases. (Ameren Ex. 45.0 Rev., p. 8.) In order to reflect this past variation (and account for the fact that further gas price variations can be anticipated into 2010), a more appropriate method of valuing gas in storage would be to use a three year average of gas prices. (Id., p. 9.) The three year average calculation smoothes out the large fluctuation of natural gas prices which can occur over a short period of time. (Ameren Ex. 65.0 (Seckler Sur.), p. 8.) Natural gas is among the most volatile commodities that are traded, so using a three year average will reduce the impact that volatility has on storage working capital. (Ameren Ex. 45.0 Rev., p. 9.)

To calculate the value of gas in storage, the AIUs used actual prices for December 2006 to August 2009. (Ameren Ex. 45.0 Rev., p. 10.) Price estimates used to record to the general ledger were used for September 2009. (Id.) Hedged gas and IFERC prices were used for October 2009, and hedged gas prices and NYMEX with basis on October 6, 2009 were used for November and December 2009. (Id.) These prices represent the most accurate to use for valuing gas in storage in this time period, since it is the end of the injection season. (Id.) The volumes were also calculated as a three year average, and adjusted for contract and other known changes. (Id.)

In the AIUs' last rate case, Mr. Lounsberry requested volumes of gas in storage be updated for known contract changes. Order, Docket 07-0585 (cons.) (Sept. 24, 2008), pp. 74-77. In response, the AIUs stated that the price of gas should be updated to match the updated volumes. Id., p. 74. The AIUs updated the value of their working capital allowance for gas in storage based on updated volumes and to reflect the AIUs' price hedging, or, where prices were not hedged, to reflect forward NYMEX strip prices for the period when rates would come into effect. Id., pp. 75-76. As the Final Order in Docket 07-0587 found, the use of the NYMEX data for the period April through October 2008 (where 2006 was the test year), which is the traditional injection season, was appropriate. Id., p. 77. The Commission concluded that, "in this instance, the price proposal of AIU is reasonable when used in conjunction with Staff's proposed quantities of gas." Id., p. 78.

Circumstances have changed since the prior case however, making the AIUs' proposed methodology appropriate in this case. As discussed above, the AIUs have seen an increase in volatility of gas prices since the prior case. In fact, Mr. Lounsberry's argument that 2008 gas prices are an "outlier" (ICC Staff Ex. 25.0 (Lounsberry Reb.), p. 10), confirms that gas prices are volatile and so are appropriately subject to averaging to smooth out the variations. In addition, in the prior case, the AIUs proposed a methodology to reflect projected gas prices during the summer injection season of 2008 because the working capital allowance for storage was calculated at the beginning of the injection season (April 2008). (Ameren Ex. 45.0 Rev., p. 9.) That concern is not present in this case, as the working capital allowance for storage is being calculated at the end of the injection season when actual prices are known (October 2009).[5] (Id.) Furthermore, using a three year average is consistent with many other price calculations for commodities with variable prices the AIUs are proposing in this rate case (such as transportation fuels).

The prices used in the three year average the AIUs are proposing, however, include the most current prices through December 2009, which is consistent with the use in Docket No. 07-0585 (cons.) of current pricing to match projected changes in volumes. (Ameren Ex. 65.0, p. 6.) The three year average calculation also sets a method or a template that can be used in future rate cases without regards to the timing of the calculation. (Id.) In addition, Ms. Seckler

[5] In fact, Mr. Lounsberry's proposal to use 2009 pricing appears inconsistent with the prior order as well, as the prior order approved use of NYMEX forward pricing to determine prices in 2008, two years after the 2006 test year in that case. Docket 07-0585 (cons.), Final Order, p. 77. Mr. Lounsberry's proposal in this case uses pricing in 2009, the year after the test year, and for which actual pricing is available for much of the year.

calculates the volume of gas in storage as a three year average (reflecting known changes), so the use of a three year pricing average matches the prices to volumes. (Id.)

Moreover, Staff is incorrect that 2008 gas prices are so different from historical and projected prices that 2008 prices must be excluded from the valuation of gas in storage. Although Mr. Lounsberry states that "a review of the 2007, 2009 and current NYMEX future prices for 2010 and 2011 demonstrates that 2008 gas prices were outliers," this analysis is based on one day's NYMEX close (11/2/09). (ICC Staff Ex. 25.0, p. 11, lines 204-05.) Reviewing the entire trading period for a specific month provides a significantly different picture. (Ameren Ex. 65.0, pp. 6-7.) For example, the simple average of the daily NYMEX closing price at which January 2011 has traded is $8.418 (1/3/08 through 11/25/09). (Id., p.7.) This price represents the approximate value that the AIUs would have had the opportunity to purchase gas on a forward contract basis to be delivered in January 2011. (Id.) If you compare this price to Mr. Lounsberry's one day settlement price on 11/2/09 for January 2011 of $6.795 and to the 2008 price AIUs used of $8.335 to $8.903, (id.), then the 2008 prices the AIUs use in their analysis cannot be considered outliers. In fact, reviewing the entire NYMEX trading period for any one month supports the three year average pricing to smooth out the volatility of natural gas prices. (Id.)

In addition, 2009 gas prices are not more representative of expected prices than Ameren's proposal. Mr. Lounsberry acknowledges that, "no one knows with certainty what the future price of gas will equal. . . ." (ICC Staff Ex. 25.0, p. 13, line 240.) He correctly points out that the NYMEX futures contracts provide an indication of the gas market's expectations for future prices. (Id.) The NYMEX futures contracts, however, also show that natural gas prices are extremely volatile. For instance, the January 2011 NYMEX contract has traded in more than a $5.00 range since it began trading until 11/25/09 (from a low of $6.426 to a high of $11.822). (Ameren Ex. 65.0, p. 8.) Given this extreme range, no one can know what future gas prices will be, which again supports using a three year average approach to calculate the value of gas in storage used for working capital purposes. (Id., pp. 8-9.)

7. OPEB Net of ADIT (Accrued OPEB Liability)

Staff and CUB/AG propose an adjustment to reduce rate base by the accrued liability for other post employment benefits ("OPEB").   The revenue requirement impact of this adjustment is approximately $7 to $8 million, plus or minus depending on which party's recommended cost of capital is assumed. This adjustment is appropriate, in part, for AmerenIP. It is not appropriate for AmerenCIPS or AmerenCILCO and should be rejected.

No party disputes that the AIUs' prudent cost of service includes the cost of OPEBs paid for former employees and retirees. OPEB is the employer's obligation for post retirement benefits, which accrues to the employee's benefit over the employee's term of service. The accounting treatment for OPEBs is prescribed by FAS 106. Whenever the cumulative amount of FAS 106 expense is greater than contributions the employer has made to the trust fund used to pay OPEBs, an OPEB liability exists. (Tr. 766-67.)

In its direct case, AG/CUB's Mr. Effron proposed an adjustment to reduce the AIUs' rate base by the level of accrued OPEB liabilities. According to Mr. Effron, "[t]he accrued OPEB liabilities represent the excess of OPEB expense recorded by the Companies over amounts actually paid, in other words, 'ratepayer supplied OPEB funds.'" (AG/CUB Ex. 2.0-C (Effron Dir.), p. 7.) Mr. Effron's claim that the entire accrued OPEB liability represents "ratepayer supplied funds" is based on an unsupported assumption that ratepayers have supplied all of the funds giving rise to the OPEB liabilities. As Mr. Stafford explained, only AmerenIP historically has funded OPEBs based in part on amounts received from ratepayers. (Ameren Ex. 29.0 Rev. (Stafford Reb.), p. 39.) An adjustment to reduce rate base by the accrued OPEB liability for AmerenIP is therefore appropriate, but only to the extent that AmerenIP's accrued OPEB liability represents ratepayer-supplied funds. (Id.) Ameren Ex. 29.17 provides the appropriate adjustment to reduce rate base by the ratepayer-supplied portion of AmerenIP's OPEB liabilities.

With respect to AmerenCIPS and AmerenCILCO, however, the AIUs historically have not directly tracked ratepayer-supplied OPEB funds. (Id.) Because ratepayer-supplied funds were not tracked, it is erroneous to conclude that these liabilities were funded entirely by ratepayers, as Mr. Stafford explains. (Id.) Indeed, contrary to funding OPEBs based on ratepayer supplied funds, funding considerations would have considered the availability of cash or borrowed funds to cover accounting accruals in accordance with FAS 106 or related accounting guidance. (Id.)

Staff adopted AG/CUB adjustment in rebuttal and argues a similar rationale. According to Ms. Ebrey, "Ratepayers have supplied funds for future obligations; therefore, a source of cost free capital has been provided to the utility which should be recognized in the revenue requirement as a reduction from rate base." (ICC Staff Ex. 15.0 (Ebrey Reb.), p. 25.)

Staff and AG/CUBs assumption that the OPEB liability represents "ratepayer supplied funds" or a source of "cost free capital" rests on the false premise that all funds received and spent by the AIUs originate from ratepayers. This is not correct. Staff admits that in the first instance, utilities are capitalized by investors. (Tr. 761.) Utilities use investor-supplied capital to invest in plant and provide service. (Id.) Part of ratemaking theory is to compensate investors by providing a return on, and return of, capital used to provide service. (Tr. 762.) Ratepayers in effect return the investment through the rates they pay. (Id.) Consequently, if rates do not include an allowance for a certain expense, investors are not compensated for that expense. For example, if a utility completes a capital project and the Commission determines that the costs were not prudently incurred, the utility will not recover the cost of that project in rates. (Tr. 763.) In this example, Ms. Ebrey agrees that it would not be accurate to say that the plant was constructed with ratepayer supplied funds. (Id.)

It is therefore beyond dispute that ratepayers provide a source of "cost free capital" for an expense item only to the extent that they have actually supplied funds for that expense item through the rates they pay. In determining whether OPEB liabilities constitute ratepayer-supplied funds, the question then becomes how many dollars have ratepayers contributed for OPEBs. Ms. Ebrey denies that it is possible to know the answer to this question. "The amounts that are recovered from ratepayers can't be identified by a specific line item on the revenue requirement because there are changes both up and down in those cost levels over time." (Tr. 768, lines 17-21.)

Ms. Ebrey is mistaken. The level of OPEB expense included in rates is based on FAS 106 -- irrespective of what the utility paid in OPEBs. (Tr. 764-65.) Although actual revenues and expenses may change after a rate case test year, the level of OPEB expense included in rates does not. If one assumes, as Ms. Ebrey does, that cumulative FAS 106 expense has been fully reflected in rates since that adoption of FAS 106, then the liability properly represents ratepayer-supplied funds, as the AIUs' agree is the case in part with AmerenIP. (Tr. 767;

Ameren Ex. 29.0 Rev. (Stafford Reb.), p. 39.) But the only way to prove this assumption is to analyze the level of FAS 106 expense recovered from ratepayers over the period giving rise to the liability, which Ms. Ebrey concedes she did not do. (Tr. 767.) Absent such an analysis, the statement that the OPEB liability constitutes "ratepayer supplied funds" or a "cost free source of capital" is wholly unsupported.[6] Mr. Effron's testimony reflects no such analysis, either.

In short, Staff and AG/CUB propose a rate base adjustment for OPEB liabilities based on an underlying assumption that these liabilities arise entirely from ratepayer-supplied funds. There is no factual support for this assumption. It is Staff and AG/CUB's burden to prove the basis for their adjustment -- the AIUs have no burden to disprove Staff and AG/CUB's unsupported assertions. It is unjust and unreasonable to eliminate from rate base the entirety of the OPEB liability on the basis of Staff and AG/CUB's unsupported assumptions. Because Staff and AG/CUB have not adequately supported their proposed adjustment, the Commission must reject it.

8. <u>Other</u>

D. Recommended Rate Base

1. <u>Electric</u>

The AIUs proposed a rate base for each utility. As a result of the adjustments discussed below, the proposed rate bases for the AmerenCILCO, AmerenCIPS and AmerenIP electric utilities are shown on Schedule 2 of Appendix A, B, and C, respectively.

2. <u>Gas</u>

[6] The AIUs' Mr. Stafford performed such an analysis in his surrebuttal testimony. This testimony was stricken by the ALJs' ruling of December 11, 2009. (Tr. 770.)

The proposed rate bases for the AmerenCILCO, AmerenCIPS and AmerenIP gas utilities are shown on Schedule 2 of Appendix D, E, and F, respectively.

III. OPERATING REVENUES AND EXPENSES

A. Overview

The AIUs presented schedules showing, for each of the gas and electric AIUs, the operating revenues, expenses, and income at present and proposed rates for the test year. Staff and other parties proposed adjustments to the AIUs' proposed operating statements as discussed below. The proposed operating income statement for the AmerenCILCO, AmerenCIPS and AmerenIP electric utilities are shown on Schedule 1 of Appendix A, B, and C, respectively. The proposed operating income statement for the AmerenCILCO, AmerenCIPS and AmerenIP gas utilities are shown on Schedule 1 of Appendix D, E, and F, respectively.

B. Resolved Issues

1. Annualized Labor

Staff recommended an adjustment to the AIUs' proposed annualized labor expense. (ICC Staff Ex. 1.0 (Ebrey Dir.), pp. 23-24, Schedule 1.09.) Specifically Staff recommended disallowance of wage increases for management employees projected for April 1, 2010 and wage increases for Union employees based on contract increases effective July 1, 2010. (Id.) To reduce the number of contested issues, the AIUs in rebuttal accepted the Staff's recommended adjustment to the AIUs' proposed annualized labor expense. (Ameren Ex. 29.0 Rev. (Stafford Reb.), p. 6; ICC Staff Ex. 15.0 (Ebrey Reb.), p. 6.)

2. FICA Corrections

Staff recommended certain corrections to the AIUs' proposed adjustments to the Companies' FICA tax expense. (ICC Staff Ex. 1 (Ebrey Dir.), pp. 26-27, Schedule 1.11.) In addition, related to its recommended adjustment to the AIUs' proposed annualized labor expense, Staff recommended a further adjustment to the AIUs' FICA tax expense. (ICC Staff Ex. 1, pp. 25-27.) To reduce the number of contested issues, the AIUs in rebuttal accepted Staff's recommended adjustment to the AIUs' proposed adjustment to the Companies' FICA tax expense. (Ameren Ex. 29.0 Rev. (Stafford Reb.), p. 6; ICC Staff Ex. 15.0 (Ebrey Reb.), p. 6.)

3. Outside Professional Services

Staff recommended an adjustment to the AIUs' Outside Professional Services expense to remove fees paid to Jacobs Consultancy, Inc. to perform an electric utility workforce analysis study for the AIUs, the results of which were to be presented to the General Assembly by the Commission. (ICC Staff Ex. 3.0 (Jones Dir.), pp. 4-5, Schedule 3.01.) To reduce the number of contested issues, the AIUs in rebuttal accepted Staff's recommended adjustment to the AIUs' Outside Professional Services expense. (Ameren Ex. 29.0 Rev. (Stafford Reb.), p. 6; ICC Staff Ex. 17.0 (Jones Reb.), p. 3.)

4. Bank Facility Fees

The AIUs have been in negotiations for a two-year bank facility in the amount of $635 million. (Ameren Ex. 2.0E Rev. (Stafford Dir.), p. 10.) Fees associated with this facility include one time arrangement and upfront fees (totaling $13.820 million, paid when the facility is put in place) and ongoing administrative agent and facility fees (totaling $5.256 million, paid quarterly after the facility is in place). (Id., pp. 10-11.) The AIUs incur these costs whether or not and regardless of the extent to which they borrow from the facility. (Id., p. 11.) Thus, through AIU witnesses Mr. O'Bryan and Mr. Stafford, the AIUs initially recommended that the fees be recovered as Administrative & General ("A&G") expenses. (Id.; AmerenCIPS Ex. 13.0E Rev. (O'Bryan Dir.), p. 7.) The AIUs' initial proposal was that the pro forma adjustment includes ongoing fees plus amortization of the one-time fees over the life of the facility and is allocated among the AIUs based on borrower sublimits. (Ameren Ex. 2.0E Rev., p. 11.)

Staff recommends the Commission reject the proposal to recover bank facility fees through A&G expenses rather than the cost of short-term debt. (ICC Staff Ex. 5.0 (Phipps Dir.), p. 13.) Specifically, Staff witness Ms. Phipps criticizes the AIUs' pro forma proposal, asserting that recovering the costs through a pro forma adjustment to operating expense assumes the upfront fees and facility fees are prudent and allocated properly for ratemaking purposes. (Id., p. 11.) She also asserts the AIUs' proposal incorrectly assigns the AIUs' non-utility costs and fails to recognize that Ameren's sublimit under the 2009 credit facility could effectively reduce the AIUs' sublimits to \$500 million from \$635 million. (Id.) Additionally, Ms. Phipps asserts "each of the AIUs allocates its costs between gas and electric delivery services using a labor cost allocator." (Id., p. 12, lines 215-16.) Thus, she states that, unless the Companies show a clear relationship between credit facility usage and labor costs, "the credit facility costs should be allocated amongst each utility's business operations based on investment, since the facility is a source of short-term debt." (Id., lines 217-19.) Finally, Ms. Phipps asserts "the actual upfront and facility fees associated with the 2009 credit facilities are lower than estimates in the AIU proposal." (Id., lines 223-24.) She calculates one-time fees for the AIUs' proportion of the 2009 credit facilities as approximately \$8.7 million and annual facility fees as \$2.2 million. (Id.)

For the purposes of this case, the AIUs accept cost recovery via the capital structure. (Ameren Ex. 29.0 Rev. (Stafford Reb.), p. 6; Ameren Ex. 37.0 Rev. (O'Bryan Reb.), p. 4.) The AIUs agree to accept Ms. Phipps' general methodology and remove bank facility fees from operating expenses and include them as a component of the capital structure consistent with Staff's recommended approach, but based on the calculation sponsored by Mr. O'Bryan.[7] (Ameren Ex. 29.0 Rev., p. 6; Ameren Ex. 37.0 Rev., p. 3.) Cost recovery of this expense via the AIUs' capital structure is discussed below in Section IV.E.

5. Uncollectibles Expenses

The AIUs initially proposed pro forma adjustments to uncollectibles expense based upon a three-year average of actual values for net write-offs for 2007 and 2008 and budgeted net write-offs for 2009. (Ameren Ex. 2.0E Rev. (Stafford Dir.), pp. 8-9.) Staff and IIEC both proposed adjustments to the AIUs' proposed Uncollectibles expense based upon the 2006 through 2008 three-year average of net write-offs as compared to revenues. (ICC Staff Ex. 1.0 (Ebrey Dir.), pp. 6-7, Schedule 1.12; IIEC Ex. 3.0 (Meyer Dir.), pp. 12-14; IIEC Ex. 3.5.) The AIUs in rebuttal subsequently proposed to substitute year-to-date actual September 2009 net write-offs and revenues for 2009 budgeted amounts. (Ameren Ex. 29.0 Rev. (Stafford Reb.), pp. 7-11; Ameren Ex. 29.4.) The AIUs noted that use of 2009 data to set rates more accurately reflects the AIUs' current uncollectibles expense, whereas use of 2006 actual data for uncollectibles expense

[7] Because the AIUs agrees to include bank facility fees as cost of capital, a separate expense lead for the bank facility fees must be calculated to reflect the specific circumstances of the payments. (Ameren Ex. 31.0 (Heintz Reb.), p. 11.) AIU witness Mr. Heintz calculates an expense lead for the bank facility fees as negative 97.65 days. (Id.) In its rebuttal testimony, Staff accepted the AIUs' presentation of bank facility fees and the expense lead time for those fees as presented in the Companies' testimony and exhibits. (ICC Staff Ex. 15.0, (Ebrey Reb.), p. 13.)

ignores a fundamental change that took place in January 2007 for pricing of electric power supply and delivery service. (Ameren Ex. 29.0 Rev., p. 8.) Staff and IIEC in rebuttal accepted the AIUs' proposal to calculate uncollectibles expense using actual 2007, 2008 and year-to-date September 2009 net write-offs. (ICC Staff Ex. 15.0 (Ebrey Reb.), pp. 6-7; IIEC Ex. 7.0 (Meyer Reb.), pp. 3-5; Ameren Ex. 51.0 2d Rev. (Stafford Sur.), p. 6.) Staff also accepted the AIUs' proposal for the associated uncollectibles rate to be reflected in proposed Uncollectibles Riders currently under consideration by the Commission in Docket No. 09-0399. (ICC Staff Ex. 15.0, pp. 6-7.)

6. Storm Expenses

The AIUs initially proposed to normalize their Storm Expense over a three-year period adjusted for inflation to reflect a trend in increased storm costs in recent years. (Ameren Ex. 2.0E Rev. (Stafford Dir.), pp. 9-10.) Staff and AG/CUB proposed to normalize the AIUs' Storm Expense over a six-year period using expense data from 2003-2008 based on the Commission use of a six-year average in Docket No. 07-0585 et al. (cons.). (ICC Staff Ex. 4.0 (Bridal Dir.), pp. 23-24, Schedule 4.08; AG/CUB Ex. 2.0-C (Effron Dir.), p. 8; AG/CUB Ex. 2.1, Schedule DJE-5.) The AIUs in rebuttal subsequently proposed to normalize Storm Expense using 2004 through year-to-date September 2009 data, instead of actual 2003 data, to better reflect the level of storm costs likely to be incurred during the period rates will be in effect. (Ameren Ex. 29.0 Rev. (Stafford Reb.), pp. 27-28; Ameren Ex. 29.12.) Staff in rebuttal did not object the AIUs' normalization approach as presented in rebuttal and accepted the Storm Expense adjustments as presented in Ameren Ex. 29.12. (ICC Staff Ex. 18.0R (Bridal Reb.), pp. 28-29; Ameren Ex. 51.0

2d Rev. (Stafford Sur.), p.6.) AG/CUB in rebuttal also found the AIUs' normalization approach as presented in rebuttal to be reasonable. (AG/CUB Ex. 4.0 (Effron Reb.), pp. 16-17.)

7. AMR Expense

Staff proposed an adjustment to remove certain conversion costs and purported non-recurring costs in the test year associated with the AIUs' Automated Meter Reading ("AMR") upgrade. (ICC Staff Ex. 3.0 (Jones Dir.), pp. 5-6, Schedule 3.03). To reduce the number of contested issues, the AIUs in rebuttal accepted Staff's proposed adjustment to AMR expense. (Ameren Ex. 29.0 Rev. (Stafford Reb.), p. 6; ICC Staff Ex. 17.0 (Jones Reb.), p. 3.)

8. Smart Grid Costs

In its Final Order in Docket No. 07-0566, the Commission directed a collaborative workshop process be held to examine the Smart Grid modernization concept and its implementation. (Ameren Ex. 1.0E (Nelson Dir.), p. 17.) In that order, the Commission stated, "[t]he purpose of the Statewide Smart Grid Collaborative is to develop a strategic plan to guide deployment of a smart grid in Illinois, including goals, functionalities, timelines and analysis of costs and benefits, and to recommend policies to guide such deployment that the Commission can consider for adoption in a docketed proceeding." (Id., p. 18.) The Final Order directed the AIUs to participate in that workshop process. (Id., p. 17.)

Also in the Final Order, the Commission stated that the least cost provisions require both that the chosen electric service be provided in the least cost manner and that the Smart Grid be at least cost, *i.e.*, the components must be optimized to provide maximum benefits to consumers subject to competitive bids, and labor must be provided at competitive rates. (Id., p. 18.) Thus, the Commission wants to better understand how the AIUs' existing systems and technology can be adapted to support a statewide goal of complying with federal policy, embodied in the Energy Independence Security Act of 2007, directing states to consider Smart Grid initiatives. (Id., pp. 18-19.) And the Commission wants to understand how implementation of Smart Grid technologies may alter costs and benefits considered when determining "least cost." (Id., p. 19.) In other words, the Commission recognizes the AIUs have already implemented facilities and technologies that will support Smart Grid efforts and that the cost/benefits framework may change to implement the final Illinois Statewide Smart Grid Collaborative ("ISSGC") vision. (Id.)

Here, the AIUs initially sought to recover $1.3 million over a three-year period, which is the AIUs' share of the costs of the third-party facilitator and workshop facility rental costs. (Id., p. 20.) Staff witness Mr. Bridal, however, proposed an adjustment to Smart Grid costs, which results from a change in the scope of Phase 2 of the project and Staff's removal of incremental costs that Staff does not believe are not known and measurable. (ICC Staff Ex. 4.0 (Bridal Dir.), p. 25.) The AIUs accepted Staff's adjustment to Smart Grid costs, to minimize the number of contested issues in this case. (Ameren Ex. 29.0 Rev. (Stafford Reb.), pp. 6-7; ICC Staff Ex. 18.0 (Bridal Reb.), p. 29.)

9. Homer Works HQ Sale

Staff proposed an adjustment to update the AmerenCILCO Electric Homer Works HQ Sale Adjustment to replace estimated amounts with actual amounts submitted by the Companies in response to Staff data request RWB 6.06. (ICC Staff Ex. 4.0 (Bridal Dir.), p. 28, Schedule 4.12.) The AIUs in rebuttal accepted Staff's proposed adjustment. (Ameren Ex. 29.0 Rev. (Stafford Reb.), p. 6; ICC Staff Ex. 18.0R (Bridal Reb.), pp. 14-15, Schedule 18.05.)

10. Social and Service Club Dues

Staff proposed an adjustment to remove all social and service club membership dues from the AIUs' recoverable operating expenses. (ICC Staff Ex. 4.0 (Bridal Dir.), pp. 22-23, Schedule 4.07.) The AIUs in rebuttal accepted Staff's proposed adjustment to remove these specific expenses from their revenue requirement, which Staff confirmed in rebuttal. (Ameren Ex. 29.0 Rev. (Stafford Reb.), p. 6; ICC Staff Ex. 18.0R (Bridal Reb.), p. 28.)

11. Charitable Contributions

Staff proposed an adjustment to remove certain contributions to community and economic development organizations from the AIUs' revenue requirement, which Staff claims are amounts for items of a promotional or business membership nature that should be the responsibility of shareholders, not ratepayers. (ICC Staff Ex. 4.0 (Bridal Dir.), pp. 17-19, Schedule 4.04.) The AIUs in rebuttal objected to Staff's proposal to include in its proposed disallowance those items that were included in the AIUs' Schedule C-7, which are recorded to account 426, a "below-the-line" account, and thereby not included in the AIUs' requested revenue requirement. (Ameren Ex. 29.0 Rev. (Stafford Reb.), p. 36.) To reduce the number of contested issues, however, the AIUs accepted Staff's adjustment to reduce the amount of charitable contributions expense referenced in the AIUs' Schedule C-2.20. (Id.; Ameren Ex. 29.13.) Staff in rebuttal accepted the adjustment to the AIUs' Charitable Contribution Expense as presented by the AIUs in Ameren Exhibit 29.13. (ICC Staff Ex. 18.0R (Bridal Reb.), p. 26; Ameren Ex. 51 2d Rev. (Stafford Sur.), p. 6.)

12. Industry Association Dues

Staff proposed an adjustment to remove certain industry association dues that Staff claimed were attributable to lobbying activities. (ICC Staff Ex. 4.0 (Bridal Dir.), p. 19, Schedule 4.05.) Staff witness Mr. Bridal calculated its adjustment by multiplying the 2008 Industry Association Dues identified by the AIUs in their Schedules C-6.1 by a lobbying percentage developed from a 2007 invoice. (Id.) Mr. Bridal in his direct testimony indicated that he had requested 2008 invoice data and might revise his proposed adjustment in rebuttal. (Id.) Staff in rebuttal revised its adjustment for Industry Association Dues based on invoices for the test year ending December 31, 2008 submitted by the AIUs in response to Staff data request RWB 19.01. (ICC Staff Ex. 18.0R (Bridal Reb.), pp. 5-10, Schedule 18.03.) The AIUs in surrebuttal agreed with Staff's proposal to calculate its adjustment based on 2008 test year invoice data, but noted that certain corrections needed to be made based on Mr. Bridal's workpapers. (Ameren Ex. 51.0 2d Rev. (Stafford Sur.), p. 23; Ameren Ex. 51.12.) Staff subsequently indicated its agreement with the adjustment concerning Industry Association Dues as presented in Ameren Exhibit 51.12. (Staff Resp. to AIU-ICC 35.01 (Ameren Group Ex. 1).)

13. <u>Advertising Expense</u>

Staff proposed an adjustment to remove from the AIUs' revenue requirement all expenses recorded in accounts 930 – Miscellaneous Advertising and General, or 930.01 – General Advertising Expenses because Staff believed that amounts recorded in these accounts were promotional, political, institutional, or goodwill in nature. (ICC Staff Ex. 4.0 (Bridal Dir.), pp. 16-17, Schedule 4.03.) The AIUs accepted Staff's proposed adjustment in principle subject to certain modifications that Staff witness Mr. Bridal indicated he would make in rebuttal in response to additional information that AIUs provided in response to data requests concerning these test year expenses. (Ameren Ex. 29.0 Rev. (Stafford Reb.), pp. 37-38, Schedule 29.15.) Staff in rebuttal accepted the Advertising Expense adjustments as presented in Ameren Exhibit 29.15. (ICC Staff Ex. 18.0R (Bridal Reb.), p. 25.)

14. Customer Service and Information Expenses

Staff proposed an adjustment to remove from the AIUs' revenue requirement certain Customer Service and Information expenses, which Staff believed consisted mainly of purchases of clothing, promotional merchandise, and sponsorships that were promotional or goodwill in nature and not allowable under Section 9-225 of the Act. (ICC Staff Ex. 4.0 (Bridal Dir.), pp. 26-27, Schedule 4.10.) Staff witness Mr. Bridal in rebuttal, however, revised his adjustment for Customer Service and Information Expenses based on his review of specific transaction data provided by the AIUs. (ICC Staff Ex. 18.0R (Bridal Reb.), pp. 10-14, Schedule 18.04.) The AIUs in surrebuttal accepted Mr. Bridal's proposed adjustment for Customer Service and Information Expenses. (Ameren Ex. 51.0 2d Rev. (Stafford Sur.), p. 34.)

15. Lobbying Expense

Staff proposed an adjustment to remove, from the AIUs' revenue requirement for all electric utilities and AmerenIP Gas, lobbying expenses that were included in Administrative and General ("A&G") accounts for the environmental services department personnel as identified in the Companies' response to Staff data request RWB 18.01. (ICC Staff Ex. 4.0 (Bridal Dir.), pp 27-28, Schedule 4.11.) Staff in rebuttal confirmed that the AIUs have accepted Staff's proposed adjustment. (ICC Staff Ex. 18.0R (Bridal Reb.), pp. 3-4, Schedule 18.01.)

16. Rate Case Expense

Staff proposed an adjustment to adjust rate case expense to account for the withdrawal and replacement of legal counsel in this proceeding and for the removal of the amortization of rate case expense from Docket Nos. 06-0070 through 391 06-0072 (cons.). (ICC Staff Ex. 4.0 (Bridal Dir.), pp. 19-22, Schedule 4.06.) The AIUs in rebuttal accepted the adjustment to the AIUs' electric utilities' rate case expense for the removal of the amortization of rate case expense related to the AIUs' prior rate case. (Ameren Ex. 30.0 (Wichmann Reb.), p. 4; Ameren Ex. 30.4.) The AIUs also accepted in principle Staff's adjustment to rate case expense to account for the withdrawal and replacement of legal counsel, but proposed that the amount of the adjustment be modified to include actual payments to prior counsel. (Id.) The AIUs also updated their rate case expense to reflect actual, rather than estimated, amounts paid to experts and consultants and actual, rather than estimated, miscellaneous legal expenses. (Id.) Staff accepted AIUs' proposed changes to Staff's adjustment to rate case expense, and recommends that the Commission allow the AIUs to recover Rate Case Expense in this docket in the amounts identified in Ameren Exhibit 30.4. (ICC Staff Ex. 18.0R, pp. 26-28.) Staff also recommends, and the AIUs concur, that the Commission expressly find that the amounts that the AIUs proposed to be expended to compensate attorneys and technical experts to prepare and litigate this proceeding are just and reasonable pursuant to Section 9-229 of the Act. (Id.)

17. Collateral Expense

The AIUs' gas operations must prepay or post collateral for certain services, due to limited access to unsecured credit, primarily caused by the AIUs' below investment grade credit ratings. (Ameren Ex. 3.0E Rev. (Wichmann Dir.), p. 11.) The collateral adjustment allows the AIUs to recover necessary costs associated with collateral posting for gas purchases. (Id.) Test year gas collateral postings have been averaged over the twelve month test year from January through December 2008, and an interest rate is then applied to the average to be consistent with the method adopted by the Commission in Docket Nos. 07-0585 through 07-0590 (cons.). (Id.)

Staff witness Ms. Jones initially proposed a collateral expense adjustment to disallow interest expense associated with collateral posting for gas purchases (ICC Staff Ex. 3.0 (Jones Dir.), p. 9, Schedule 3.07.) Ms. Jones believed such an adjustment was appropriate, even though, in the Companies' previous rate proceeding, the Commission found "it is appropriate for AIU to pass the cost of collateral on to ratepayers through base rates." (Id., lines 161-63.) She explained that, in the previous rate proceeding, the Companies testified that they were incurring costs associated with prepayment and collateral posting for gas purchases because of diminished and limited access to unsecured credit as a result of the reduction in their credit ratings and that such costs would remain necessary until they carry investment-grade ratings. (Id.) Ms. Jones asserted that her adjustment to disallow interest expense associated with collateral posting for gas purchases would reflect what she believed was the case – that the AIUs now carry investment-grade ratings and the cost of collateral should no longer be necessary. (Id.)

As explained by AIU witness Mr. O'Bryan, however, Ms. Jones' removal of collateral expenses from the test year is not appropriate. (Ameren Ex. 37.0 Rev. (O'Bryan Reb.), pp. 9-10.) Ms. Jones' assumption that the AIUs no longer incur collateral expenses because their credit ratings were recently upgraded is incorrect. (Id.) While it is true that investment grade credit ratings improve the AIUs' access to unsecured credit, the AIUs have effective ratings at the lowest investment grade notch for the purposes of a very high percentage of contracts. (Id.) Generally, the higher the effective rating, the greater the access to unsecured credit. (Id.) Thus, while the AIUs now carry investment grade ratings, they had positive collateral postings in place with their counterparties as of October 22, 2009. (Id.) The amounts of collateral will vary according to the transactions executed and the applicable forward pricing curves. (Id.) As long as collateral may be contractually required by the AIUs' counterparties, there will be a cost associated with posting such collateral. (Id.) After reviewing Mr. O'Bryan's testimony, Ms. Jones withdrew her proposed adjustment. (ICC Staff. Ex. 17.0 (Jones Reb.), p. 4.)

18. Company-Use and Franchise Gas

In his direct testimony, Staff witness Seagle recommended that the Commission reduce the Companies' request for their company-use and franchise gas expenses. (ICC Staff Ex. 13.0 (Seagle Dir.), p. 3) Mr. Seagle stated that the gas pricing that the AIUs used to value their requested franchise gas amounts resulted in an overstatement of gas prices on a going forward basis and recommended alternative pricing. (Id., pp.28-29.) On rebuttal, the AIUs agreed with Mr. Seagle's proposal and updated the franchise gas pricing as Mr. Seagle recommended. (Ameren Ex. 30.0 (Wichmann Reb.), p. 6.) Mr. Seagle also recommended that the AIUs provide rebuttal testimony that updates each of the AIUs' company-use gas costs using the most recent gas pricing information available and normalizes the volumes. (ICC Staff Ex. 13.0, p. 26.) On rebuttal, the AIUs agreed with Mr. Seagle's proposal and updated the company-use gas pricing and volumes as Mr. Seagle recommended. (Ameren Ex. 30.0, p. 5.) Staff agreed with the calculations the AIUs provided on rebuttal regarding the AIUs' company-use gas costs and franchise gas costs. (ICC Staff Ex. 26.0 (Seagle Reb.), p. 3.)

19. Real Estate Taxes

Staff proposed an adjustment for AmerenCIPS Gas to remove amounts included in Real Estate Taxes that Staff argued represented prior period adjustments, and not actual test year real estate taxes. (ICC Staff Ex. 4.0 (Bridal Dir.), p. 29, Schedule 4.14.) To reduce the number of contested issues, the AIUs in rebuttal accepted Staff's Schedule 4.14 adjustment for AmerenCIPS Gas, as shown on Ameren Exhibit 30.2, Schedule 1, Page 5 of 5, column (o).

20. Prior Period HMAC

Staff proposed an adjustment for AmerenIP Electric to remove what Staff believed were 2007 HMAC costs from the revenue requirement. (ICC Staff Ex. 1.0 (Ebrey Dir.), p. 30, Schedule 1.16.) To reduce the number of contested issues, the AIUs in rebuttal accepted Staff's proposed adjustment to remove "Prior Period HMAC costs" from the revenue requirement of AmerenIP. (Ameren Ex. 29.0 Rev. (Stafford Reb.), p. 6; ICC Staff Ex. 15.0 (Ebrey Reb.), p. 6.)

C. Contested Issues

1. Tree Trimming

Consistent with the approach adopted by the Commission in the prior two electric delivery services rate cases, the AIUs propose a pro forma adjustment to test year Electric Delivery Services operating expenses to reflect 2010 budgeted tree trimming/vegetation management expenses. (Ameren Ex. 2.0E Rev. (Stafford Dir.), p. 7.) This adjustment is based on the current four-year trimming cycle applicable to all AIUs' electric operations. (Id.) Notably, the AIUs' proposal does not include any cost for conversion to a "no contact" zone approach – a conversion Staff suggests and that necessitates a more frequent trimming cycle to maintain "no contact" for the entire service area. (Id.) Thus, if the Commission requires the

AIUs to convert to Staff's approach, the additional associated costs would need to be added to the AIUs' pro forma level of operation and maintenance expense for their Illinois Electric Delivery Service Operations. (Id., pp. 7-8.)

To ensure the reasonableness of the 2010 budget, the AIUs started with actual 2008 tree trimming expenses, reviewing the work performed in 2008 and related costs. (Ameren Ex. 26.0 Rev. (Nelson Reb.), p. 6.) This was compared to the work to be performed in 2010 and its projected costs, taking into account the four-year trim cycle requirements, Staff's expectations for reliability enhancement measures, and contracts with vegetation management contractors and local labor unions for negotiated wage increases. (Id.) This approach played out as follows: In 2008, the AIUs' combined actual tree-trimming expenses totaled $39.2 million, and the 2009 projected amount (based on 8 months of actual and 4 months of projected data) is $39.2 million. (Id.) From this information, the AIUs project $39.3 million expected actual tree-trimming expenses to be included in their combined revenue requirement. (Id.)

Staff – through Staff witness Ms. Jones – proposes to reduce the AIUs' tree trimming expenses. (ICC Staff Ex. 3.0 (Jones Dir.), p. 7; ICC Staff Ex. 17.0 (Jones Reb.), p. 6.) To compute her adjustment, Ms. Jones calculated an annual average amount, based on the AIUs' actual tree trimming expense for 2005 through 2008 and January 1 through June 30, 2009. (ICC Staff Ex. 17.0, Schedule 17.02) Ms. Jones' proposal allows only $34.6 million of tree-trimming expenses, which is approximately $4.7 million less than the AIUs are reasonably certain to incur in 2010. (Id.)

The AIUs' responses to Staff data request revealed that, while trimming is planned for 24% (roughly ¼) of the total AIU system in 2010, the percentages for each AIU vary from 33% to

17% – based on number of circuits – or from 28% to 19% – based on number of circuit miles. (ICC Staff Ex. 17.0, p. 6.) According to Ms. Jones, this data shows that the amount of work and associated costs to maintain a four-year trim cycle within each Company varies from year to year. She observes that a company would not need to trim 28% of its circuit miles each year to maintain a four-year cycle, nor could a company that trims only 19% of its circuit miles each year maintain a four-year cycle. (Id., pp. 7-8.) She explains that the average of costs incurred by each utility over a period of time smoothes cost variances and provides a reasonable amount of tree trimming expense to include in the respective company's revenue requirement. (Id., p. 8.) Thus, she bases her proposal on her belief that some companies are going to receive too much revenue requirement. (Tr. 187.)

While Ms. Jones contends that some companies may trim more than 25% in 2010, and some companies may trim less, she reduces tree trimming expenses for all three companies. This is a mathematical impossibility if the total trimming is ¼ of the entire system. Thus, her adjustment should be rejected on arithmetic grounds alone.

Moreover, contrary to Ms. Jones' suggestion, the AIUs provided evidence to support its position that the amount of tree trimming expense projected in the 2010 budget is the appropriate amount of tree trimming expense for the 2008 historical test year. (Ameren Ex. 49.0 2d Rev. (Nelson Sur.), p. 10.) This evidence was provided in response to Ms. Jones' series of data requests, BCJ 12.01 through BCJ 12.08. (Id.) In fact, the Superintendent of Vegetation Management for the AIUs sponsored several of these responses and asserts the responses accurately provide Staff with information regarding the AIUs' 2010 tree trimming activities.

(Ameren Ex. 62.0 (Tate Sur.), p. 2.) Staff seems to disregard this evidence. (Ameren Ex. 49.0 2d Rev., p. 10.)

If the Commission adopts Staff's proposal, the AIUs will need to synchronize expenditures to rate recovery by spending $4.7 million less than the amount needed for tree trimming functions in 2010 and beyond. (Ameren Ex. 26.0 Rev., p. 11.) Staff's recommendation will be less than required to achieve the four-year tree trimming cycle across the AIUs' entire service territories. (Id.)

Both the Commission and Staff recognize the importance of a four-year trim cycle, as evidenced by the Commission's acceptance of Staff's repeated recommendations in their annual reliability assessment reports. (Id., p. 12.) For example, the Illinois Commerce Commission Assessment of AmerenIP's Reliability Report and Reliability Performance for Calendar Year 2007 – which the Commission accepted – recommended AmerenIP "should do whatever is necessary to maintain a four-year (minimum) tree trimming cycle that is also in compliance with 2002 NESC Rule 218 throughout its service territory." (Id.) Additionally, Staff's findings in the February 14, 2008 Staff Report to the Commission, on the Assessment of the Ameren Illinois Electric Utilities' Reliability for 2006, included similar recommendations for all the AIUs. (Id.) And, importantly, in Docket No. 00-0699, the Commission ordered AmerenCILCO to a four-year trim cycle, and AmerenIP and AmerenCIPS voluntarily committed to the Commission to do the same. (Id., pp. 11-12) Thus, if the Commission adopts Staff's position, AmerenCILCO must petition the Commission to alter its four-year cycle requirement. (Id., p. 12; see also Order, Docket 02-0248 (Dec. 4, 2002), p. 43 ("[T]he Commission does not hereby intend to, alter, limit or otherwise affect any of CILCO's obligations with regard to CILCO's accelerated tree trimming program. . . .").)

In addition, if Staff's adjustment is adopted, the AIUs will not be able to continue reliability-enhancement tree trimming programs. (Id., p. 13.) The AIUs will trim fewer trees, and the likelihood for less reliable service will increase. (Id.) Specifically, "if the Commission determines [the AIUs] should spend $4.7 million less than what [they] think is really required to provide adequate service to [the AIUs'] customers, then [the AIUs are] going to take that as direction . . . and adjust [] spending to correspond to the revenue requirement allowed by the Commission in this and other areas." (Tr. 54-55.) Although $4.7 million is a "relatively small percentage of the total revenue request," it "can have a significant impact." (Tr. 55.) Staff's tree trimming adjustment is wholly unsupported and should be rejected.

2. Incentive Compensation Expenses

The Commission has a well-established policy of permitting recovery of incentive compensation expense where the utility has demonstrated that its incentive compensation plans result in tangible benefits for ratepayers. Order, Docket 05-0597 (July 26, 2006), pp. 96-97 (allowing recovery of 50% of incentive compensation costs where utility demonstrated benefits for ratepayers); Order, Docket 03-0403 (Apr. 13, 2004), p. 15. In a recent decision, the Commission clarified the above standard when it stated that, with respect to the formulation for recovering incentive compensation, "[t]he main and guiding criterion is that the expense be prudent, reasonable and operate in a way to benefit the utility's customers." Order, Docket 07-0241 (Feb. 6, 2008), p. 66.

Furthermore, in the AIUs' prior rate case, the Commission approved recovery of 50% of the AIUs' requested incentive compensation expense, based on the determination that incentive plans related to certain operational goals (safety, reliability and customer service) provided direct, meaningful benefits to ratepayers, and payouts for these goals were not dependent upon meeting financial targets. Order, 07-0585 (cons.) (Sep. 24, 2008), pp. 107-08. The Commission considered evidence from the AIUs in that case regarding the operational and individual goals of their incentive compensation plans and how the metrics benefited AIU customers by enhancing service, increasing service reliability, and/or increasing the efficiency of operations. Id., p. 102. The Commission concluded, "[t]he record indicates that AIU has in place incentive compensation plans related to safety (weighted 25%), customer service (weighted 10%), and reliability (weighted 15%) that also do not appear to have payouts that are dependent upon Ameren meeting financial targets. In the Commission's view, it is reasonable to allow AIU to pass the cost of these portions of the incentive compensation plans on to customers." Id., p. 108.

The AIUs request recovery in this case for the same type of expenses—those that provide direct, meaningful benefits to ratepayers. The AIUs have satisfied the above standards by providing extensive information relating the customer benefits of their incentive plans' operational goals in testimony and discovery responses. (Ameren Ex. 42.0 (Lindgren Reb.), p. 5; Ameren Ex. 42.1) In light of the determination in the AIUs' prior case, it is the AIUs' position that a showing that the AIUs have incentive compensations plans in place that are "related to" areas such as safety, customer service and reliability that benefit ratepayers is sufficient to obtain recovery of incentive compensation expense. As the record shows, however, the AIUs have provided even more extensive information demonstrating that all their key performance indicators ("KPIs") provide ratepayer benefits. Thus, the Commission should permit recovery of the AIUs' requested incentive compensation expense. See Order, Docket 04-0442 (Apr. 20, 2005), p. 54 (accepting the utility's incentive compensation plan where it was "virtually identical to the plan in a previous docket").

The AIUs seek recovery of the portions of their incentive compensation expense related to operational goals (expenses related to earnings per share financial goals were removed from the AIUs' request for recovery). As Mr. Lindgren explained, incentive compensation is a common and necessary component of the total compensation package for employees in the electric and gas utility industry. (Ameren Ex. 42.0, p. 7.) Moreover, the AIUs' incentive plans focus primarily on awarding employees based on their performance relative to operational goals that benefit the ratepayer (*e.g.*, customer service, reliability, safety, operational efficiency, etc.) (Id.) As Mr. Lindgren explained, by designing a market-competitive incentive plan that rewards employees for achieving operational goals that they are most able to influence and control, the AIUs are able to attract and retain the most qualified talent in the electric and gas utility industry while motivating the highest level of performance in key areas that have a direct, positive impact benefiting the ratepayer – customer service, reliability, safety, and operational efficiency. (Id., pp. 7-8; Ameren Ex. 42.1.)

As Mr. Lindgren indicated, the AIUs' employees[8] participate in one of four annual incentive compensation plans:

[8] Employees of Ameren Services (AMS) also participate in the same plans. (See Schedule (2.12; WPC 2.12b.)

- The Executive Incentive Plan for officers ("EIP-O"), which applies to all officers within the AIUs.
- The Executive Incentive Plan for managers and directors ("EIP-M"), which applies to all members of the Ameren Leadership Team ("ALT") with the exception of officers.
- The Ameren Management Incentive Plan ("AMIP"), which applies to the AIUs' professionals and supervisors (excluding ALT and bargaining unit employees).
- The Ameren Incentive Plan ("AIP"), which applies to employees who are represented by a bargaining unit.

(Ameren Ex. 18.0E (Lindgren Dir.), p. 4.)

A certain percentage of the EIP-O and EIP-M is funded based on financial performance. (Ameren Ex. 18.0E, p. 4.) Costs related to these financial goals have been removed from the AIUs' requested incentive compensation expense. (Ameren Ex. 1.0E Rev. (Nelson Dir.), p. 10.) The remaining goals for these programs, however, are based on operational performance as measured by incentive KPIs. (Ameren Ex. 18.0E, p. 5.) Incentive KPIs generally represent goals related to important operational issues such as safety, reliability, customer satisfaction, and operational excellence. (Id.) The AMIP is funded based on achievement of pre-defined incentive compensation KPIs. (Id.) These KPIs focus plan participants on key operational metrics such as safety, reliability, cost control, and customer satisfaction. (Id.) The AIP is funded and paid 100% based on incentive KPI performance. (Id.) The incentive KPIs are designed to focus employees on important operational goals that they can influence. (Id.) Incentive compensation paid under the AIP does not include the O&M Budget Compliance and/or Capital Budget Compliance measures. (Ameren Ex. 42.0, p. 3.)

In their direct case, the AIUs provided evidence describing the operational goals and related ratepayer benefits associated with 2008 incentive compensation expense.[9] (Ameren Ex. 18.0E, pp. 2-6.) In addition, the AIUs provided substantial information regarding incentive compensation KPIs in information provided to Staff pursuant to 83 Ill. Admin. Code Section 285.150 and through discovery. As Ms. Ebrey acknowledged on cross examination, she reviewed information regarding incentive compensation expense provided in response to over 20 data responses, as well as information obtained during Staff field work, in interviews with AIU human resources personnel and through various other telephone conversations. (Tr. 776-78; AIU Ebrey Cross Exhibit 1.)

Despite the extensive information provided to Staff regarding the AIUs' incentive compensation expense, in her direct testimony, Ms. Ebrey proposed to disallow all test year incentive compensation expense, both the expense associated with capital and O&M budget compliance measures, as well as other expense for which the AIUs, in her opinion, failed to "quantify" ratepayer benefits or otherwise calculate the "net benefits" to customers. (ICC Staff Ex. 1.0 (Ebrey Dir.), pp. 9-18.) Ms. Ebrey claimed that the AIUs were "unable to provide any benefit to customers of employee attainment of the operational goals on the 2008 Scorecards," based on their response to an ICC Staff data request. (Id., p. 12.)

[9] For the 2008 test year, the following KPIs are associated with incentive payout under the plans: O&M & Capital Budget Compliance (weighted 20%); Safety (weighted 20%); Reduced System Interruption (weighted 10%); Energy Efficiency (weighted 10%); Reliability (weighted 10%); Gas Leak Response (weighted 10%); Customer Service (weighted 10%); and Earnings per share (weighted 10%). (Ameren Ex. 18.0E (Lindgren Dir.), pp. 2-3.) Furthermore, the current 2009 KPI's are: O&M Budget Compliance (weighted 20%); Energy Efficiency (weighted 15%); Safety (weighted 20%); Gas Operations & Maintenance (weighted 15%); Customer Service (weighted 15%); and Reliability (weighted 15%). (Id.)

The AIUs, therefore, provided further information in the rebuttal testimony of AIU witness Lindgren (Ameren Exs. 42.0, pp. 4-7; 42.1.) that demonstrated that the operational goals associated with the AIUs' incentive compensation plans provided real benefits to customers. Ameren Exhibit 42.1 provides a detailed summary of the ratepayer benefits of significant KPI's. (Id.) For example, the "Meet Gas Leak Response Objectives," tracks response performance to customer initiated calls to AIU where a gas odor is present. (Ameren Exhibit 42.1, p. 1.) The AIUs respond and investigate every gas leak call that is received. The accepted criteria for a prompt response are "as soon as possible but no more than an hour." The AIUs, however, have gone beyond the accepted criteria and established additional KPI criteria: responding to each leak in an average of less than 25 minutes. In 2007, the AIUs responded to over 34,000 gas leaks within one hour 99.8% of the time and the average response time was about 23.4 minutes. In 2006, the AIUs responded to 99.5% of all gas leaks within one hour and 24.2 minutes for an average response. Thus, the AIUs' evidence on this KPI shows not only ratepayer benefits but an improvement in performance. See, e.g., Order, Docket 03-0403 (April 13, 2004), pp. 29-33 (approving recovery of incentive compensation expense including those expenses related to not incurring regulatory violations, as ratepayers were the primary beneficiaries).

Mr. Lindgren also explained how KPIs for O&M Budget Compliance and capital budget compliance provide ratepayer benefits in the EIP-M and the AMIP. (Ameren Ex. 42.0, p. 3.) The establishment and focus on budget targets provides benefits to ratepayers by setting a goal for managing overall expenditures for projects and services within a defined period of time. (Id.) Cost management/cost control is beneficial to customers to assure dollar resources are spent on priority initiatives and within the desired timeframe. (Id.) This helps ensure that customers receive quality service in the most cost-effective manner. (Id., pp. 3-4.) A focus on budget/cost control helps reinforce AIUs' culture of cost management and finding new ways to reduce expenditures while improving service and customer satisfaction. (Id., p. 4.) Ratepayers benefit from this. (Ameren Ex. 49.0 2d Rev. (Nelson Sur.), p. 15.)

Ms. Ebrey acknowledged the ratepayer benefits of certain KPIs in her rebuttal testimony, when she stated that "[c]ertain KPIs included on Ameren Exhibit 42.1 are based on Surveys, Indices, and duration of service interruptions. The specific goal targets do illustrate the customer benefit. Therefore, I am allowing recovery of the costs associated with those goals." (ICC Staff Ex. (Ebrey Reb.), p. 11, lines 207-10.) Ms. Ebrey further acknowledged that "[i]n addition, certain other KPIs are based on response or performance time to meet customer needs. These are also based on specific measurements which I consider to be of benefit to customers. I am allowing recovery of costs associated with those goals." (Id., lines 211-14.)

Staff also remains concerned that the incentive compensation costs associated with KPIs for O&M Budget Compliance and Capital Budget Compliance are based on financial goals. While the Commission has previously disallowed recovery of incentive compensation related to financial goals or triggers, O&M and Budget Compliance KPIs are not related to financial goals, as discussed above. In fact, the Commission has previously approved the recovery of incentive compensation expense related to goals of reducing O&M and capital expenses. In Docket 05-0597, the Commission found: "Focusing on the funding measure that rewards employees for reducing O&M and capital expenses, the Commission finds that such funding measure meets the Commission's standard of reducing expenses and creating greater efficiencies in operations.

Lowering O&M expenses, all else being equal, has the obvious effect of reducing the expenses to be recovered in future rate cases." Order, Docket 05-0597 (July 26, 2006), p. 96, aff'd Commonwealth Edison Co v. Illinois Commerce Comm'n, Case No. 2-06-1284 (cons.), pp. 11-14 (2d Dist, Sept. 17, 2009) (upholding Commission's decision to deny recovery of the 50% of incentive compensation expense based on financial goals but to allow recovery for other components of incentive compensation expense). The AIUs have demonstrated that the costs associated with O&M Budget Compliance and Capital Budget Compliance provide such benefits. Consistent with the Commission's ruling in Docket 05-0597, recovery of these expenses should be allowed.

In summary, Staff continues to propose removal of incentive compensation expense associated with certain KPIs, based on the AIUs' alleged failure to perform a highly specific cost-benefit analysis with respect to each individual KPI. (ICC Staff Ex. 15.0, pp. 9-10.) This detailed cost-benefit analysis differs from the type of showing utilities have made, and the Commission has accepted, in the past to demonstrate "tangible ratepayer benefits." It applies a higher standard to recovery of incentive compensation costs than that applied for recovery of almost all other O&M and capital costs. (Ameren Ex. 49.0 2d Rev., p. 16.) There is no basis, however, for imposition of such a higher standard. In fact, as Ms. Ebrey admitted at hearing, she does not contend that in order to show that a KPI produces a ratepayer benefit, such benefit must be a quantified financial benefit. (Tr. 782-83.) Thus, it appears that Staff now agrees that the recovery of incentive compensation expense requires demonstrating tangible ratepayer benefits, but such demonstration does not depend on a cost benefit analysis of each individual

KPI. The AIUs have shown their incentive compensation plans provide ratepayer benefits. Therefore, the AIUs' requested incentive compensation expense should be allowed.

3. Pension, OPEB and Major Medical Expenses (including Production Retiree Expenses)

The AIUs' cost of service includes pension and OPEB expenses for current and former employees. The financial meltdown that occurred in the Fall of 2008 caused a significant decline in plan assets used to pay benefits, resulting in an increase in pension and OPEB expense beginning in 2009. (Ameren Ex. 38.0 (Lynn Reb.), p. 3.) Because actual 2008 pension and OPEB expense is not representative of either actual 2009 expense or expense that will be incurred in 2010 when new rates go into effect, the AIUs propose to establish test year expense based on twelve months of actual expense for the period October 2008 through September 2009. (Ameren Ex. 51.0 2d Rev. (Stafford Sur.), p. 7.) The use of actual expense amounts for the year following the test year is consistent with the treatment of pension and benefits expense in the AIUs' two most recent cases, Dockets 06-0070/0072 (cons.) and 07-0585/90 (cons.). (Ameren Ex. 29.0 Rev. (Stafford Reb.), p. 12.)

Staff argues that pension and benefits expense for the 12 month period ending September 30, 2009 is not known and measurable, and therefore proposes to establish pension and benefits expense based on calendar year 2008 data. (ICC Staff Ex. 15.0 (Ebrey Reb.) pp. 18-19.) Staff takes this position notwithstanding Ms. Ebrey's acknowledgement that the value of securities used to fund the AIUs' pension and OPEB plans decreased significantly in 2008, resulting in an increased level of pension and benefits expense that began to be recognized in 2009. (Tr. 755-56.) That aside, Ms. Ebrey claims that "[t]he entries for pension costs for the months during 2009 are based on the reports prepared by Towers Perrin at January 2009 and

July 2009. The actual Pension Cost for the year ending December 31, 2009 and the Employer Contribution for the Plan Year Beginning January 1, 2009 will not be determined until the year end 2009 actuarial study has been completed, after the record in these proceedings will be marked heard and taken." (ICC Staff Ex. 15., p. 19.) Staff's adjustment for pension and benefits expense would reduce the AIUs' aggregate revenue requirement by almost $16 million.[10]

Staff's proposed adjustment reflects a misunderstanding of the accounting for pension and benefits expense and should be rejected. Mr. Randall Lynn of Towers Perrin (the AIUs' pension and OPEB actuary) explained that the calculation of pension and OPEB expense is determined by Accounting Standards Certifications 715-30 and 715-60 (ASC 715), formerly FAS 87 and 106, respectively. (Ameren Ex. 54.0 (Lynn Sur.), p. 2.) Under ASC 715, employee census data, plan asset values and financial market conditions as of the last day of the prior year are used to develop pension and OPEB expense for the following year. (Id.) Thus, 2009 pension and OPEB expense is based on a valuation using data as of December 31, 2008. (Id.) The year-end financial data for the prior year is used to prepare quarterly reports that the AIUs use to record pension and OPEB expense for the following year. (Id., p. 4.) The first quarter report is based on estimated employee census data. (Id.) Actual census data is used for the second quarter report. (Id.) Third and fourth quarter reports are also based entirely on actual data. (Id.)

Thus, when the valuation report is completed for the second quarter of each year, the pension expense for that year is already known and measurable. As demonstrated in the

[10] Staff's derivative adjustment for production retiree expense (ICC Staff Ex. 15.11) is dependent on the Commission's decision regarding pension and OPEB expense. (ICC Staff Ex. 15.0, p. 22.) The AIUs accepted Staff's proposed adjustment for capitalized production retiree costs (ICC Staff Ex. 15.0, p. 6).

comparison provided in Ameren Ex. 54.1, expense levels will not vary from the second quarter valuation report to the final valuation report unless there is a "significant event," as determined by ASC 715, such as a material workforce reduction or acceleration of benefits. (Ameren Ex. 54.0, p. 5.) The last "significant event" that occurred for the AIUs was the 2004 acquisition of Illinois Power. (Id.) No significant events have occurred since, nor are any expected. (Id., pp. 3-4.)

Considering how pension and OPEB expense are accounted for under ASC 715, Staff's claim that these expenses "will not be determined until the year end 2009 actuarial study has been completed" is simply not correct. The July 1, 2009 Towers Perrin report (Ameren Ex. 38.2) provides a known and measurable level of pension and OPEB expense that has been incurred through September 2009. There were no "significant events" in the third quarter of 2009, and even if a significant event occurred in the fourth quarter (and one has not), such an event would not affect pension and OPEB expense for prior quarters. (Ameren Ex. 54.0, p. 5.)

The July 2009 valuation report thus provides reliable, probative evidence of pension and OPEB expense booked in 2009 through September. Staff acknowledges that the amounts provided in this report are the same amounts recorded on the books of the AIUs. (ICC Ex. 15.0, pp. 18-19.) Staff also acknowledges that in determining the appropriateness of any pro forma adjustment, "all the evidence should be considered," including recent actual data where available. (Tr. 756, line 13; see also Tr. 757, lines 1-6.) Ms. Ebrey, however, assumes that the amounts booked through September 30, 2009 could change when the final actuarial report is issued. (Tr. 754-55.) No reason, no rationale and no record evidence are cited to support this assumption. Not only is this assumption not supported by the record; it is contrary to it. Mr.

Lynn confirmed that the amounts booked through September 30, 2009 will not change when the final report is issued in early 2010.[11] (Ameren Ex. 54.0, p. 5.) Mr. Stafford also noted that expenses through September 2009 have already been incurred and recorded on the books of the AIUs and will not change. (Ameren Ex. 51.0 2d Rev., p. 10.). And it is undisputed that pension expense for the 12 month period ending in September 2009 significantly exceeds 2008 expenses, by $16 million. If the AIUs' rates do not reflect this increased level of expense, the AIUs will most assuredly fail to recover their authorized rate of return.

Staff also makes the curious claim that the AIUs have "selectively picked significant expense items and propose[] to update them to the most current amounts recorded on the utility books." (ICC Staff Ex. 15.0 (Ebrey Reb.), p. 19.) The AIUs' proposal to establish pension and OPEB expense based on the 12 months ending September 30, 2009 is well within the period for pro forma adjustments allowed by 83 Ill. Admin. Code Part 287.40. Ms. Ebrey admits that Staff itself has proposed a number of adjustments based on 2009 actual data. (Tr. 757.) And in the AIUs' last two rate cases, pension and OPEB expense was based on data for the year following the test year. (Ameren Ex. 29.0 Rev. (Stafford Reb.), p. 12.) The AIUs' proposal does not violate test year principles in any way.

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[11]Mr. Lynn testified that the final 2009 valuation report will be completed by February 1, 2010. The AIUs do not believe it is necessary, but are willing to submit the final report to Staff and the Commission for review when it becomes available. (Ameren Ex. 51.0 2d Rev. (Stafford Sur.), pp. 11-12.) The Commission would be well within its authority to consider this additional evidence should it choose to do so. See, e.g., Order, Docket 07-0566 (Sept. 10, 2008), pp. 16-17 (discussing Stipulation agreed to by Staff for Commonwealth Edison to provide, post-hearing, a late-filed exhibit or compliance filing reconciling actual and projected pro forma capital additions). Moreover, although Ms. Ebrey testified that submission of the final 2009 actuarial report will not satisfy her concern because the report will be stated for the calendar year 2009 and not the 12 months ending September 30, 2009, she acknowledges that there is no Commission rule that requires pension and benefits expense to be calculated on a calendar-year basis as opposed to some other 12 month period. (Tr. 760.)

The AIUs have fully supported their proposed pro forma adjustment for pension and OPEB expense based on data for the 12 month period ending September 30, 2009. Staff's adjustment is unsupported by the record and should be rejected.

4. NESC Expenses

Staff proposes that the Commission disallow recovery of certain capital costs and expenses incurred by the AIUs in bringing certain facilities into compliance with the National Electric Safety Code ("NESC"). (ICC Staff Ex. 11.0R (Rockrohr Dir.), pp. 12-23; ICC Staff Ex. 24.0R (Rockrohr Reb.), pp. 7-11.) The Commission should reject Staff's recommended disallowance.

As explained in the testimony of AIU witness George Justice, the AIUs seek recovery of only a portion of their NESC-related repair costs: their costs for "new work" repairs to bring facilities into compliance with NESC without rebuilding existing infrastructure or duplicating work previously performed. (Ameren Ex. 11.0E Rev. (Justice Dir.), pp. 3-11; Ameren Ex. 35.0 (Justice Reb.), pp. 4-12; Ameren Ex. 66.0 (Justice Sur.), pp. 2-6.) With respect to these NESC-related "new work" repairs, Staff contends that ratepayers should not pay now to install parts that should have been installed when the infrastructure was initially constructed. (ICC Staff Ex. 24.0R, pp. 8-9.) But the AIUs are not seeking to recover the costs of fixing incorrectly installed or constructed infrastructure. Rather, the AIUs seek recovery of the costs of installing infrastructure components that were missing entirely. Adding on missing parts to existing infrastructure does not charge ratepayers a second time to correct improperly constructed facilities. It is fair and reasonable for the AIUs to recover NESC-related "new work" costs from ratepayers in instances where the repairs do not require the AIUs to reconstruct existing infrastructure or redo work previously done improperly.

The AIUs' recovery of NESC-related expenditures does not turn on whether those expenditures were necessary and prudent. No party to this proceeding has suggested that the NESC-related repairs at issue should not have been performed or were not performed at a reasonable cost. The AIUs have pursued vigorously the enhancement of their acquired electric infrastructure to correct problems that existed prior to their ownership and to ensure safe and reliable distribution systems since their ownership. Specifically, the AIUs have implemented a system-wide Circuit Inspection Program to, among other things, find and resolve NESC-related violations on their circuits. (Ameren Ex. 11.0E, p. 3.) The AIUs have submitted to Staff an NESC Corrective Action Plan that sets forth a commitment and timeframe for inspecting all of their Illinois distribution circuits and correcting all existing NESC violations. (Id.) Indeed, Staff witness Mr. Rockrohr has testified that the AIUs' inspection program has been effective at finding and addressing NESC violations. (ICC Staff Ex. 11.0R, p. 13.) There is no dispute that the AIUs' NESC-related repairs and the related costs are necessary and prudent.

Instead, the dispute between the AIUs and Staff concerns whether it is appropriate to allocate to ratepayers any portion of these prudent and necessary NESC-related costs, specifically the costs incurred in conducting certain "new work" repairs. In its Final Order in the AIUs' prior rate case, the Commission determined that "ratepayers will not be responsible for paying the costs associated with correcting distribution facilities that were initially constructed in a manner that does not comply with the NESC." Order, Docket Nos. 07-0585-0590 (Cons.) (Sept. 24, 2008), p. 142. The Commission stated that "ratepayers should [not] be responsible for paying the cost associated with improperly constructed electric distribution facilities as well as the cost of correcting the improperly constructed facilities." Id. (emphasis added).

According to Mr. Rockrohr, the Docket 07-0585-0590 (cons.) Order supports the conclusion that if "the ratepayers already paid the utility for the installation," the AIUs "should not charge ratepayers a second time" to properly install the infrastructure. (ICC Staff Ex. 11.0R, p. 14, lines 323-26.)

Staff's position fails because the AIUs are not asking ratepayers to pay twice to construct distribution infrastructure in compliance with the NESC. In the 2008 test year, the AIUs performed over 52,000 reliability and corrective repairs on their circuits. (Ameren Ex. 11.0E Rev., p. 5; Ameren Ex. 11.1.) Out of the 25 types of repairs performed, the AIUs identified 11 categories of repairs that concerned NESC issues. (Id.) The AIUs spent a total of approximately $13.1 million for these 11 categories of NESC-related repairs. (Ameren Ex. 11.0E Rev., p. 5.) The AIUs, however, do not seek recovery of all, or even a majority, of these repair costs. Cognizant of the Commission's concern that ratepayers not pay twice to properly construct infrastructure in compliance with the NESC, the AIUs are not seeking to recover "re-work" costs. For example, the AIUs do not ask for recovery of costs to correct improperly placed insulators on guy wires. (Id., p. 8.) Likewise, the AIUs do not seek recovery of costs to correct inadequate line clearance where lines were installed too close to the ground, another wire or structure. (Id., p. 9.) The AIUs also do not seek recovery of costs to replace low brackets on underground risers. (Id., p. 10.) Of the $13.1 million in NESC-related repair costs, the AIUs excluded approximately $8.7 million spent on "re-work" repairs from their request for cost recovery in this proceeding.[12] (Ameren Ex. 35.1.)

Having excluded "re-work" repair costs, the "new work" costs for which the AIUs seek recovery in this proceeding total approximately $4.4 million. Staff, however, contends that a large portion of the AIUs' NESC-related "new work" costs are really "re-work" costs that should be disallowed. Staff recommends that 90% of the AIUs' test year costs to place guy guards on existing guy wires,[13] 100% of their costs to install insulators on existing guy wires and 100% of their costs to ground existing underground risers be considered "re-work." (ICC Staff Ex. 11.0R, pp. 18-23; ICC Staff Ex. 24.0R, p. 8.) But the installation of missing guy guards, insulators and grounds does not require the AIUs to reconstruct improperly constructed infrastructure. (Ameren Ex. 11.0E Rev., p. 6; Ameren Ex. 35.0, p. 5.; Ameren Ex. 66.0, pp. 3-4.) Unlike the "re-work" repairs necessary to correct inadequate wire clearance, remove low brackets from risers or replace improperly placed insulators, the installation repair work simply requires the AIUs to add missing parts to existing infrastructure. The cost of installation is essentially the cost required to complete construction of the infrastructure in compliance with the NESC. Because

[12] The AIUs in their direct case initially identified approximately $8.6 million in NESC-related "re-work" costs and $4.5 million in NESC-related "new work" costs. (Ameren Ex. 11.0E Rev., p. 6; Ameren Ex. 11.1.) On rebuttal, the AIUs proposed adjusting their NESC "re-work" costs upwards slightly to approximately $8.7 million to include a portion of the test year costs incurred in installing insulators to existing guy wires. (Ameren Ex. 35.0, pp. 10-12; Ameren Ex. 35.1.)

[13] Staff witness Rockrohr estimates the percentage of locations where guy guards are removed after initial installation as "very small" based on his experience at non-AIU electric utilities and proposes that the AIUs be allowed to recover 10% of their guy guard installation costs. (ICC Staff Ex. 11.0R, p. 19.) The AIUs, however, estimate the percentage of guy guard removed within the AIUs' service territory at 90%. (Ameren Ex. 35.0, p. 9) If the Commission accepts in principle Mr. Rockrohr's adjustment, the AIUs still should recover 90 percent of its test year costs for installing guy guards on existing guy wires. (Ameren Ex. 66.0, p.5.)

the parts were never installed and the work was never performed, ratepayers were never charged for the costs associated with the installation. Approving recovery of such NESC-related “new work” installation costs is consistent with the Commission’s Order in the AIUs’ prior rate case because ratepayers are not being charged a second time. The work was never done in the first place. Customers ultimately benefit from the AIUs completing construction of the guy wire or riser infrastructure in compliance with NESC. It is therefore fair and reasonable to recover these additional installation costs from ratepayers.

Staff also argues that the costs to install the parts at the time the infrastructure was initially constructed would have been negligible in comparison to the test year costs. (ICC Staff Ex. 11.0R, pp. 18, 20, 22-23; ICC Staff Ex. 24.0R, pp. 9-10.) The added cost to install these missing parts, however, whether incurred during the test year or at the time of initial construction of infrastructure, is identifiable, quantifiable and material. In preparing their direct case, the AIUs calculated a reasonable average cost for each “new work” and “re-work” repair, relying on specific project data from actual work orders and job requests from the 2008 test year. (Ameren Ex. 66.0, pp. 4-5.) In preparing their rebuttal case, the AIUs relied on the same cost data and actual field experience to derive a reasonable average labor cost for a specific step in the process of installing insulators in existing guy wires that could be considered “re-work.” (Ameren Ex. 35.0, pp. 11-12.) In response to Staff data requests, the AIUs explained the basis and methodology for their cost calculations and also calculated the average man-hours to install these parts. (Ameren Exs. 66.1-2.) This analysis demonstrates that the installation of these parts at the initial time of construction would have resulted in additional billed time for labor. (Ameren Ex. 35.0, pp. 6-10.) Because the work was not performed, ratepayers did not pay this additional labor cost. In addition, the parts themselves would have remained in the AIUs inventory for future use. Ratepayers would not have paid for these parts until they were used. (Ameren Ex. 35.0, p. 6-7.) Thus, ratepayers did not pay for the labor or materials required to install missing parts at the time the infrastructure was constructed.[14]

The AIUs' proposal to recover $4.4 million in NESC-related "new work" repair costs–roughly one-third of their test year costs to conduct all NESC-related repair work–fairly and reasonably allocates to ratepayers only those NESC-related costs that were never incurred when the infrastructure was initially constructed. In contrast, Staff's proposal to disallow all NESC-related costs to install missing parts improperly allocates to the AIUs' shareholders costs never before passed along to the AIUs' ratepayers. The AIUs' test year NESC-related "new work" costs are not costs incurred in moving or removing an already improperly placed part; they are not costs incurred in reconstructing or rebuilding distribution infrastructure originally built in violation of the NESC; and they are not costs incurred in redoing work that was not done correctly the first time. Thus, the AIUs' recovery of this discrete subset of NESC-related costs does not charge ratepayers a second time to correct improperly constructed facilities. Staff's proposed disallowance of these NESC-related "new work" costs should be rejected.

5. Amortization of IP Merger Expense/Regulatory Asset

As Mr. Stafford explained, in Docket 04-0294, the Commission approved a reorganization that resulted in the merger of Illinois Power with Ameren, creating the entity

[14] In addition, there is no return cost associated with performing NESC-related "new work" repairs, since these repairs are conducted concurrently with non-NESC-related repairs performed on the same circuit due to the proximity of workers conducting non-NESC work to locations in need of NESC-related repairs. (Ameren Ex. 35.0, pp. 4-6.)

now known as AmerenIP. (Ameren Ex. 29.0 Rev. (Stafford Reb.), p. 28.) As part of this reorganization, the Docket 04-0294 Order authorized AmerenIP to record up to $67 million of merger-related costs as a regulatory asset and amortized between 2007 and 2010. Order, Docket 04-0294, p. 25. AmerenIP will not fully recover the authorized $67 million by December 2010. (Ameren Ex. 29.0 Rev., p. 34.) Under-recovery of accounting amortization is over $16 million, due to previously authorized recoveries in the rate orders in Dockets 04-0476, 06-0070-72 (cons.) and 07-0585-90 (cons.). (Id., pp. 34-35.) Thus, test year amortization is $16.75 million, which represents the balance of the authorized $67 million regulatory asset not yet recovered. (Id., p. 29.)

Staff, AG/CUB and IIEC object to including the full test year amortization in rates. Staff argues that any recovery after 2010 is prohibited by the Docket 04-0294 Order. (ICC Staff Ex. 2.0 (Everson Dir.), pp. 12-13.) AG/CUB and IIEC argue that because the remaining amortization will be $11.167 million when new rates go into effect in May 2010, AmerenIP will over recover the regulatory asset if new rates are in effect for more than one year. (AG/CUB Ex. 2.0-C (Effron Dir.), p. 9; IIEC Ex. 3.0 (Meyer Dir.), pp. 10-11.) Staff and IIEC propose to amortize the balance of the regulatory asset over two years. (ICC Staff Ex. 2.0, p. 13; Tr. 799; IIEC Ex. 3.0, p. 10.) AG/CUB proposes a three year amortization. (AG/CUB Ex. 2.0, p. 8.)

To reduce the number of contested issues, the AIUs agree with the Staff and IIEC approach of amortizing the remaining balance of the regulatory asset, calculated as of May 2010, over two years. (Ameren Ex. 51.0 2d Rev. (Stafford Sur.), p. 3; Ameren Ex. 51.11; Staff Resp. to AIU-ICC 27.02 (Ameren Group Ex. 1).) This adjustment is reflected in AmerenIP's statement of operating income. (Ameren Appendix C, Sch. 1, p.4, Ameren Appendix F, Sch. 1, p.

3.) If the Commission adopts this proposal, the AIUs request that the Commission make an express finding that the AIUs be permitted to adjust their regulatory asset amortization at May 1, 2010, as recorded in the books of AmerenIP, to match the same two year period established for rates.

6. Economic Development Expenses

The AIUs seek to recover approximately $600,000 of labor and labor-related expenses[15] incurred by the Ameren Economic Development Department (and accounted for in Account 912) in the AIUs' approved operating expenses. The Commission should allow recovery for these prudently-incurred expenses for the reasons that follow.

As explained by AIU witness Michael Kearney, the Economic Development Department ("Department") provides economic development services to the AIUs to assist Illinois service area communities (consisting of AIUs' ratepayers) in attracting new business and investment, which supports the economic viability and sustainability of service area community economies in terms of population growth and maintenance, housing, new investment, and improved tax base. (Ameren Ex. 70.0 (Kearney Sur.), p. 3; Tr. 76-80.) For the AIU customers' communities, the Department provides technical services and programs to help enhance the local/regional economic development capacity, support community planning, and successfully prepare those communities to compete for new business investment and retention. (Id.; see also Ameren Ex. 70.1 (describing current community development programs).) For business development, the Department partners with local/regional/state governmental and non-governmental

[15] "Economic development labor and labor-related costs" refer to the labor and labor-related costs associated with the specific operating activities performed by the Economic Development Department for the AIU. (Ameren Ex. 70.0 (Kearney Sur.), p. 3.)

development organizations to attract new business growth and investment by engaging in business outreach activities regarding business location assistance services available via the AIUs. (Ameren Ex. 70.0, p. 4.) The Department is also the point-of-contact for new and expanding business inquiries and offers Illinois communities programs to support canvassing of business for retention and expansion opportunities to utilize existing infrastructure. (Id.)

The AIUs have shown that the services provided by the Department benefit the AIUs' ratepayers across all customer classifications in the communities and businesses with whom the Department works. (Id.) For example, the AIUs' business and community development services provide economies of scale to programs and activities that would otherwise not materialize. (Id.) The Department's efforts to add new customers to the AIUs' existing delivery infrastructure system have the added benefit of spreading fixed operating costs across a broader customer base, which ultimately benefits all ratepayers. (Id., p. 5.) In addition, the Department works with the AIUs' customers and customers' communities to avoid plant closure, job loss and community disinvestment. The Department also supports existing customers to ensure continued and efficient use of existing delivery infrastructure and works to avoid any disruption to existing service when connecting new industrial or commercial customers. (Id.)

Mr. Kearney provides an example of the tangible results of the Department's efforts. In 2008, the Department helped support the location/expansion of new business, which resulted in the projected creation of 546 direct new jobs throughout its Illinois service territory, an additional 855 projected new indirect jobs resulting from project multiplier effects, and approximately $222 million in new project investment in Illinois. (Id., pp. 5-6.) With each location/expansion, the Department coordinated development activities on behalf of the AIUs until the electric meter was properly installed and the prospect was a customer of record for the AIUs. (Id., p. 6.) No party has disputed either the essential services provided by the Department during these projects or the tangible benefits enjoyed by the AIUs' customers as a result.

Notably, at the hearing, Staff witness Mr. Bridal essentially agreed with the AIUs' premise for seeking recovery of the labor and labor-related expenses of the Department – that the Department's work directly and indirectly benefits the AIUs' customers. First, Mr. Bridal agreed that the Department provides an essential function by answering questions from customers about the provision of utility service, including questions regarding expanding service or consuming service more efficiently. (Tr. 869.) Second, Mr. Bridal also testified that the AIUs generally should work to avoid any disruptions to utility service when connecting new customers "at all times" – something the Department does when working with future customers. (Tr. 869-71.) He also agreed that the AIUs should recover the costs associated with doing so. (Tr. 872.) Third, Mr. Bridal agreed that, as a general matter, customers who have a job are in a better position to pay their bills than customers who do not. (Tr. 867-68.) All customers benefit when people pay their bills on time because of the reduced level of uncollectibles expense. Finally, Mr. Bridal agreed that the AIUs' customers benefit from the AIUs' efforts to actively increase their customer base because doing so spreads the fixed operating costs of the AIUs across a larger number of customers. (Tr. 872-73.)

At bottom, no one disputes the calculation of the approximately $600,000 of labor and labor-related economic development expenses of the AIUs. And it has been shown that the

Department's work directly and indirectly benefits the AIU customers and is an integral part of the provision of utility service. As such, the costs as identified in Ameren Ex. 29.14 should be recovered in rates.

7. Workforce Reduction

AIU witness Mr. Nelson discusses the Ameren buyout offer. The AIUs agree that an adjustment to labor and associated expenses (such as payroll taxes) is warranted to reflect decreased salary and benefits expense that will occur as a result of the buyout. Staff, however, has miscalculated the appropriate adjustment. The Commission should adopt the workforce reduction adjustment reflected in Ameren Exhibit 51.9.

Staff's workforce reduction adjustment is flawed in four respects. The most serious flaw is Staff's failure to recognize that the long-term savings that will result from the workforce reduction come at a short-term cost. These costs total just over $2.7 million and consist mainly of employee severance payments. (See Ameren Ex. 49.0 2d Rev. (Nelson Sur.), p. 9.) Ms. Ebrey considers severance costs "a onetime cost which does not reflect a normal on-going level of cost," and on that basis proposes to disallow severance costs in their entirety. (ICC Staff Ex. 15.0 (Ebrey Reb.), p. 21.) The one-sidedness of this approach is obvious, for it provides ratepayers the full benefit of the cost-savings associated with workforce reductions while saddling the AIUs' shareholders with all of the costs necessary to achieve those benefits. (Ameren Ex. 49.0 2d Rev., p. 21.)

Rather than disallow severance costs in their entirety, as Ms. Ebrey proposes, a more rational (and fairer) approach is to amortize these costs over a period of three years. (Id.) No party has argued that the severance costs incurred by the AIUs were unreasonable or imprudent; nor can they. To disallow these severance costs is to send a message to utilities that necessary and prudent workforce reductions will be punished financially. This would be a radical departure from past practice, where the Commission has recognized that utilities should not be punished for incurring short-term severance costs that produce long-term reductions in the cost of service. Thus, in Docket 05-0597, the Commission approved amortization of severance costs incurred by ComEd in implementing its "Exelon Way" severance program, notwithstanding objections by AG that these were one-time, nonrecurring costs. Order, (July 26, 2006), p. 70, "The record is clear that there are already savings from the Exelon Way program that will be reflected in the rates in this proceeding." Id.; see also Order, Docket 92-0448/0239 (cons.), 1994 Ill. PUC LEXIS 437 (Oct. 11, 1994), pp. 236-237 (approving amortization of severance costs.) The same is true here, where Staff's adjustment reflects the savings that will be realized from the AIUs' workforce reductions. The workforce reduction adjustment must be calculated net of severance costs, as shown in Ameren Exhibit 51.9.

Second, Staff's adjustment double-counts incentive compensation expense. As Mr. Stafford explained, Staff's adjustment reflects the full amount of test year incentive compensation expense, without considering the portion of incentive compensation expense that the AIUs removed in their direct case or the portion that Staff proposes to disallow. (Ameren Ex. 51.0 2d Rev. (Stafford Sur.), p. 13.) Mr. Stafford corrected this double-counting by developing a ratio of the AIUs' surrebuttal request for incentive compensation recovery, divided by total incentive compensation for the 2008 plans, in order to measure the portion of expense separately removed from the revenue requirement. (Id.) He applied this percentage to the workforce reduction-related incentive compensation adjustment to remove accounting for the same reduction in two separate adjustments. (Id.) Because Ameren Exhibit 51.9 is calculated based on the AIUs' surrebuttal incentive compensation position, to the extent the Commission adopts any portion of Staff's incentive compensation adjustment, the incentive compensation component of the workforce reduction adjustment must also be adjusted downward, on a proportionate basis, to avoid double counting. (Id.)

Third, Staff's adjustment also double counts the payroll tax component of the workforce reduction adjustment. Ms. Ebrey separately calculated an associated payroll tax adjustment, not realizing that data provided by the AIUs showing payroll tax savings already accounted for a lower level of payroll tax associated with the workforce reductions. (Id., pp. 13-14.) Ameren Exhibit 51.9 corrects this double-counting.

Fourth, Staff's adjustment improperly includes transmission-related costs. With regard to electric service, the AIUs provide both transmission and distribution service. (Id., p. 14.) Thus, the A&G portion of salary and benefits expense allocable to transmission service should be excluded from the adjustment because these costs are not recoverable in distribution rates. (Id.) Ameren Exhibit 51.9 properly recalculates the salary and benefits adjustment to remove transmission-related costs.

The adjustments proposed in Ameren Exhibit 51.9 are fully supported by the record and should be adopted.

8. Electric Distribution Tax/Public Utilities Revenue Act Tax

The Public Utilities Revenue Act, 35 ILCS 620, levies a tax on electric utilities based on the total amount of energy delivered in a year at different rates for up to seven different kwh sales blocks. (Ameren Ex. 16.0E 2d Rev. (Jones Dir.), pp. 11-12.) Although all parties recognize that this tax is part of the cost of service and must be recovered in rates, this issue nonetheless spawned several points of contention.

The first issue is whether the expense should be recovered in base rates or through a separate rider mechanism. This issue is now uncontested. (Sec. V.B.2.) The AIUs agreed with Staff's recommendation to continue to recover the distribution tax through base rates. (Ameren Ex. 40.0 2d Rev. (Jones Reb.), p. 3.) IIEC also agrees that base rate recovery of this expense is appropriate. (IIEC Ex. 1.0-C (Stephens Dir.), pp. 24-27.)

A second issue is whether the expense should be allocated on a per-kwh basis or, instead, allocated on the same basis as general plant. This issue is discussed in Sections VI.C.1.d and VII.C.2.c.

The third issue concerns Staff and IIEC's proposed revenue requirement adjustments associated with the distribution tax. The AIUs propose a pro forma adjustment to restate test year expense associated with the electric distribution tax to be consistent with the use of weather-normalized kwh sales in the calculation of revenues at present rates. (Ameren Ex. 2.0E Rev. (Stafford Dir.), p. 17.) Weather normalized sales are then multiplied by current statutory tax rates to arrive at the pro forma amount for this tax. (Id.) IIEC and Staff object to this adjustment because it does not account for refunds/credits routinely received by the AIUs' for overpayment of the tax.[16]

Based on the fact that the AIUs receive periodic refunds/credits and did not reflect these in their adjustment, Staff in its rebuttal testimony takes the extreme position that the pro

[16] The amount of the distribution tax is statutorily limited. If the statutory limit is reached in any given year, revenues received in excess of the cap are refunded to all electric utilities in proportion to their payments. (See IIEC Ex. 1.0-C (Stephens Dir.), p. 21.)

forma adjustment should be eliminated in its entirety. (ICC Staff Ex. 15.0 (Ebrey Reb.), pp. 22-23.) A more even-handed approach would be to simply correct the adjustment to reflect the refunds/credits, as IIEC's Mr. Stephens proposes. (IIEC Ex. 5.0-C (Stephens Reb.), pp. 17-18.) Mr. Stephens's approach adopts use of weather normalized kwh sales applied to statutory tax rates. Since these sales are used to calculate delivery service revenues, there is a matching of sales used to derive revenues with sales used to calculate expense. (Ameren Ex. 51.0 2d Rev. (Stafford Sur.), p. 24.) Mr. Stephens's approach has the added benefit of eliminating the impact of prior period adjustments to prior period accruals that may exist with the per-books distribution tax expense. (Id.) Ameren Ex. 51.13 reflects Mr. Stephens's approach and should be adopted as the basis for determining the recoverable test year electric distribution tax expense.

9. Transportation Fuel Expense

The AIUs' cost of service includes the cost of gasoline and diesel fuel used to operate fleet vehicles and construction equipment. The AIUs originally calculated their test year transportation fuel expense based on actual fuel costs for calendar year 2008. (ICC Staff Ex. 13.0 (Seagle Dir.), pp. 20-21.) However, acknowledging Staff's concern that fuel prices have declined from levels reached during 2008 and to reduce the number of contested issues, the AIUs subsequently proposed in rebuttal that this expense be normalized for purposes of this proceeding by calculating the AIUs' average gasoline and diesel fuel costs over a three year period from August 2006 through July 2009. The AIUs' normalization method captures the variation and fluctuations in prices that actually have occurred for gasoline and diesel fuel in recent years. (Ameren Ex. 34.0 Rev. (Getz Reb.), p. 21; Ameren Ex. 61.0 Rev. (Getz Sur.), p.3.)

As a result, the AIUs propose a downward adjustment to their original request for fuel expense of approximately $367,000 for the gas utilities and $899,000 for the electric utilities.[17] (Ameren Ex. 61.1-61.2.)

Staff, however, proposes that the AIUs' average fuel costs be calculated (and adjusted further downward) using prices from only a one year period from August 2008 through July 2009. (ICC Staff Ex. 26.0R (Seagle Reb.), pp. 15, 19-22; ICC Staff Ex. 17.0 (Jones Reb.), Schedules 17.01.) The Commission should reject Staff's proposed adjustment. Staff admits that fuel expense is volatile. (Tr. 634.) Staff admits that any number of factors beyond the utility's control can cause fuel prices to fluctuate rapidly. (Tr. 635-36.) And Staff admits that normalization of a volatile, fluctuating expense over a historical period accounts for volatility and smoothes out fluctuations. (Tr. 637-39.) Staff's calculation of the AIUs' average fuel costs, however, simply relies on period of time that (i) is too narrow and (ii) largely encompasses a decline fuel prices in the second half of 2008 and depressed fuel prices during the first half of 2009. It is inappropriate to normalize a volatile and rapidly fluctuating expense item like transportation fuel costs by selectively relying on only a 12 month period of time where the prices in large part were abnormally low.

Staff asserts that its calculated average fuel costs is representative of the fuel costs that the AIUs will experience in the second half of 2010 when the rates from this proceeding will go into effect. (Tr. 654.) But EIA's latest 2010 forecast issued in December 2009 already shows an average price for gasoline 37 cents higher (2.88 vs. 2.51) and for diesel fuel 18 cents higher

[17] The amount of transportation fuel expense initially sought was approximately $1.914 million for the gas utilities and $4.372 million for the electric utilities. (Ameren Ex. 61.1-61.2.)

(2.96 vs. 2.78) than the average fuel prices in the 12 month period relied on by Staff. (Tr. 655-58; AIU Cross Exhibit Seagle No. 9.) In contrast, the AIUs have proposed their own adjustment to 2008 test year fuel expense using a three year period of pricing data, from August 2006 through July 2009, which appropriately accounts for price fluctuations and volatility. The AIUs' calculation captures not only the higher prices experienced in the first half of 2008, but also the lower prices experienced in the second half of 2008 and first half of 2009 that Staff relies on in its calculation. Indeed, even with the higher 2008 prices included in the AIUs' normalization, the average price of gasoline calculated by the AIUs (2.83) is actually less than the average price of gasoline for 2010 based on the EIA forecast issued in December 2009 (2.88).[18] (Ameren Ex. 34.9; AIU Cross Exhibit Seagle No. 9.)

In its direct case, Staff objects that reliance on 2008 test year transportation fuel costs "results in an overstatement of costs going forward because fuel prices have not remained at their 2008 level." (ICC Staff Ex. 13.0, pp. 19-20.) Staff could have proposed to calculate a normalized level of fuel expense over a certain number of years to lessen the impact of the higher prices in 2008. Indeed, Staff witness Mr. Seagle admits that "[it]t is not unreasonable to normalize fuel prices since the item . . . is a volatile or fluctuating expense item." (Tr. 637.) Mr. Seagle further admits that "more often than not [the] historical period of time that is examined to normalize an expense is a number of years." (Tr. 639.) In fact, Mr. Seagle himself recommends a normalization adjustment to AmerenIP's test year expense for Account 887 based on a three-year average of historical expenses. (Tr. 641.)

[18] Moreover, the average price of diesel fuel calculated by the AIUs' (3.05) is much closer to the average price of diesel fuel for 2010 based on the latest EIA forecast (2.96) than the Staff's proposed average price of diesel fuel (2.78). (Ameren Ex. 34.9; AIU Cross Exhibit Seagle No. 9.)

But in making his adjustment to the AIUs' test year transportation fuel expense, Mr. Seagle did not rely on a three-year, or even two-year period of data, to calculate the AIUs' average fuel costs. (Tr. 640.) Instead, Mr. Seagle's "average" relies solely on a historical 12 month period. (Tr. 636, 640-41.) Staff should agree that 12 months is too narrow a period of time to properly normalize a volatile expense. It was Staff, after all, that initially objected to the AIUs' use of a 12 month period to calculate their transportation fuel costs. Indeed, Mr. Seagle agrees that "in some cases" "the more volatile an expense item is, the longer the period of time the normalization period should be." (Tr. 639.)

In actuality, Staff does not propose to normalize this expense. Rather, Staff essentially proposes to shift the AIUs' 2008 test year period forward seven months, to August 2008 through July 2009, to mask the reality of higher fuel prices that occurred earlier in 2008.

Staff objects that 2008 test year prices are "outliers" that "should not be considered in the calculation of average [fuel] prices." (ICC Staff Ex. 26.0R, pp. 16-17.) But Staff itself relies on 2008 data in its proposed calculation of the AIUs' average fuel costs; Staff just selectively relies on fuel prices from the second half of 2008, when the United States was in the midst of an economic recession and fuel prices plummeted.[19] (Tr. 636.) The AIUs agree that fuel prices rose during the first half of 2008 and then sharply declined in the second half. (Ameren Ex. 61.3.) This does not mean that the low price period should be considered and the high price period ignored. The very purpose of normalizing a volatile expense item is to smooth out the

[19] Indeed, Mr. Seagle believes that "the last economic recession [] that impacted everything in the world" was the Great Depression in 1929. (Tr. 660.) Yet, the 12 month period relied on by Mr. Seagle to calculate the AIUs' average fuel costs (August 2008 – July 2009) falls squarely during the 2008-09 recession when fuel prices declined and remained depressed. (Ameren Ex. 61.3.)

peaks and valleys in costs. To rely solely on pricing data from the narrow window of time from August 2008 through July 2009 ignores the actual higher fuel prices experienced by the AIUs in the first half of 2008, prior to the economic downturn and financial crisis. Even though fuel prices may have risen during the first half of 2008, it is appropriate to include those higher prices in a normalization, just as it is appropriate to include in the calculation unusually low prices, such as those experienced by the AIUs in the second half of 2008 and first half of 2009. By Staff's logic, fuel prices from late 2008 and early 2009, which were the lowest prices experienced by the AIUs in years, (Ameren Ex. 61.3), should be excluded from Staff's own calculation of average fuel costs.

Staff further claims that the 2010 price forecast issued by the Energy Information Administration (EIA) in October 2009 shows no trend for fuel prices in 2010 to return to levels reached in 2008. (ICC Staff Ex. 26.0R, p. 17; Tr. 644.) Even if 2010 forecasted prices prove that certain higher 2008 prices should be selectively excluded from the calculation of the AIUs' average fuel prices – and they do not – EIA's short-term forecasts do not foreclose the possibility the fuel prices could rapidly rise in 2010. As Staff recognizes, EIA's short-term price forecasts are issued and revised upward or downward on a monthly basis. (Tr. 644.) These revisions can be significant. For example, comparing the EIA 2010 forecast issued in January 2009 to the one issued in October 2009 shows that, in the past few months, forecasted prices for 2010 already have been revised upward by an average of 21% for gasoline and 9% for diesel fuel. (Ameren Ex. 61.0 Rev., pp. 5-6; Ameren Ex. 61.4; Tr. 645-46.)

Not only are EIA's monthly forecasts frequently revised; on occasion they are wildly inaccurate. Comparing EIA's October 2007 forecast of 2008 prices to actual 2008 prices shows that EIA failed to predict a sharp increase in prices that actually occurred. Actual prices in 2008 were on average 15% higher for gasoline and 28% higher for diesel than prices EIA projected in the fall of 2007. (Ameren Ex. 61.0 Rev., p. 6; Ameren Ex. 61.5; Tr. 648-49.) Given the number of external variables that can cause the fuel prices to fluctuate rapidly, such as consumer demand, conflicts in oil producing regions, cuts in production by OPEC, refinery capacity, and even hurricanes in the Gulf (Tr. 634-36), there can be no assurances that fuel prices will not vary significantly from the EIA October 2009 forecast relied on by Staff.[20]

Mr. Seagle himself admits that "the volatility of gasoline and fuel prices makes it difficult to predict or forecast fuel prices." (Tr. 646.) He admits that he does not know what the actual fuel prices in 2010 will be. (Id.) And he admits that he cannot rule out the possibility that fuel prices in the period when rates will be in effect will reach or even exceed levels reached in 2008. (Tr. 647.) Thus, to claim that EIA price forecasts prove that gasoline and diesel fuel prices in 2010 will not match or exceed 2008 prices is pure speculation. Nor should these forecasts justify the exclusion of actual prices that the AIUs already experienced in 2008 from the calculation of the AIUs' transportation fuel expense. As noted above, even with the higher 2008 prices included in the AIUs' normalization, the AIUs' calculated average fuel prices (2.83 for gasoline and 3.05 for diesel) actually resemble closely the average fuel prices for 2010 based on the EIA's latest price forecast (2.88 for gasoline and 2.96 for diesel).

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[20] For example, comparing EIA's forecast for fall 2005 prices to actual fall 2005 prices shows yet another instance where EIA failed to predict an increase in gasoline and diesel fuel prices that actually occurred (after Hurricane Katrina purportedly impacted U.S. crude production and refinery capacity in August 2005). (Tr. 651-54.)

The record therefore demonstrates that Staff's methodology for adjusting the AIUs' actual 2008 test year transportation fuel expense is flawed. Staff's methodology does not account for the volatility in fuel prices and understates the AIUs' actual fuel expense over the past several years. Staff's proposed average fuel costs do not even represent what the AIUs' fuel costs likely would be if the EIA's latest 2010 price forecast turns out to be accurate. The three-year normalization proposed by the AIUs is the appropriate methodology for treating the fluctuations in the AIUs' transportation fuel costs to calculate a reasonable level of recoverable expense. The Commission should accept the AIUs' normalization approach and their proposed adjustment to the 2008 test year fuel expense.

10. Account 887 Expense –Maintenance of Mains

In order to render safe, adequate and reliable gas delivery service, the AIUs must perform both routine and special maintenance on gas distribution mains. The distribution expenses associated with these gas maintenance activities are collected in FERC Account 887, otherwise known as the "Maintenance of Mains" account. The AIUs initially requested recovery of approximately $4.981 million in expenses for AmerenIP's Account 887 for the 2008 test year. (Ameren Ex. 30.5; ICC Staff Ex. 13.0 (Seagle Dir.), p. 16.) In response to Staff's objection that expense in this account has trended upward in recent years and to limit the number of contested issues, the AIUs subsequently proposed, for purposes of this proceeding only, to normalize expense for this account using amounts for a three-year period ending September 2009. (Ameren Ex. 30.0 (Wichmann Reb.), p. 5; Ameren 51.0 2d Rev. (Stafford Sur.), pp. 25-26.) As a result, the AIUs requested in rebuttal recovery of only approximately $3.780 million in expense for this account, which represents a downward adjustment of $1.201 million from the amount initially requested. (Ameren Ex. 30.5.)

Staff, however, rejects AIUs' proposed use of more recent 2009 data to normalize expense for AmerenIP's Account 887. (ICC Staff Ex. 26.0R (Seagle Reb.), pp. 10-14.) Staff asserts that the AIUs are "unable to explain or provide any basis" for why the costs in this account have increased from 2006 through 2008.[21] (Id., p. 13.) Staff claims that the AIUs' testimony and responses to data requests "failed to provide any supporting data that demonstrated that the dramatic cost increases to Account 887 [between 2006 and 2008] were just and reasonable." (Id., p. 12.) But in responding to the AIUs' normalization approach in rebuttal, Staff fails to explain why more recent actual 2009 data should not be used in the calculation of an average expense for this account. Instead, Staff continues to maintain that AmerenIP's Account 887 expense should be averaged using older expense data from calendar years 2006-2008. (ICC Staff Ex. 17.0 (Jones Reb.), Schedule 17.04.) As a result, Staff requests an additional downward adjustment of $665,000 for this expense compared to the AIUs' rebuttal request. (ICC Staff Ex. 26.0R, p. 14.)

The AIUs disagree in principle with Staff's approach to selectively review and normalize the expense for one account based on prior period spending simply because the test year expense for that account may be higher than in previous years. Such an approach fails to consider that costs associated with a utility's recurring business activities can impact any particular account differently from year to year. (Ameren Ex. 30.0, p. 5.) It is neither

[21] The expense for AmerenIP's Account 887 for 2006 was $1.589 million and for 2007 was $2.978 million. (ICC Staff. Ex. 13.0, pp. 16-19.)

unreasonable nor unexpected for a utility's maintenance expense to vary annually depending on the type and number of projects required to repair damaged distribution infrastructure, replace obsolete assets and expand systems to meet customer demands and improve reliability of service.

Moreover, comparing the expense for Account 887 for the 12 months ending September 2008 ($4.318 million) and September 2009 ($4.451 million) confirms that the 2008 test year expense is not an abnormally high amount. Rather, the 2009 data confirms that the expense associated with this account is trending upward. Despite this upward trend, the AIUs seek recovery of only $3.780 million. (Ameren Ex. 30.5).

The AIUs also disagree with Staff's assertion that they are "unable to explain or provide any basis" for the increase or "failed to provide any supporting data" to demonstrate that the increase is "just and reasonable." (ICC Staff Ex. 26.0R, pp. 12-13.) Staff acknowledges that the AIUs have identified the specific costs that contributed to the increase in expense in this account and have explained that the increase was largely due to increased costs for union and management labor and labor relating loadings. (ICC Staff Ex. 13.0, p. 17.) It is neither unreasonable nor unexpected for AmerenIP's maintenance expense to trend upward based on incremental increases in costs associated with labor and inflation. Staff is therefore mistaken to suggest that the AIUs have not provided any basis or explanation for the increase in expense in this account.

Having said all of the above, for purposes of this proceeding only and in an attempt to limit contested issues, the AIUs agreed to Staff's recommendation to normalize the expense for AmerenIP's Account 887. What the AIUs do <u>not</u> agree with is Staff's reliance on older, outdated data to calculate an average expense. Use of more recent 2009 data to normalize this expense is appropriate to better reflect recent activity for this account and the level of expense that the AIUs are likely to incur during the period that rates set in this proceeding will be in effect.

In response to the AIUs' proposal to include 2009 data, Staff simply repackages its complaints that the AIUs have not supported the reasonableness of the 2008 test year expense. (ICC 26.0R, pp. 11-12.) But Staff fails to explain why use of more recent data in the averaging calculation is not appropriate, especially when Staff has used 2009 data when proposing adjustments for other expenses. (Tr. 757.) Indeed, Staff witness Mr. Seagle concedes that he relied on 2009 pricing data to calculate the AIUs' average fuel costs, but failed to rely on 2009 data in making his proposed adjustment to AmerenIP's Account 887 expense. (Tr. 642.)

The AIUs agreed to normalize the expense in AmerenIP's Account 887 over a number of years to satisfy Staff's concern that the expense for the 2008 test year is somewhat higher than in previous years. Staff's proposal to use older, outdated data in the calculation of an average expense for this account unreasonably increases the adjustment to the 2008 test year expense already agreed to by the AIUs. Rates are set prospectively, not retroactively, so what the expense was historically for this account is not as relevant as what the expense is now and what it will be going forward. Accordingly, the Commission should accept the AIUs' proposal to normalize this expense based on data from the three-year period ending September 2009.

11. Injuries and Damages Expense

The AIUs' cost of service includes payments made to settle injury and damage claims. Because this expense fluctuates from year to year, the AIUs propose to normalize this expense for the test year. The AIUs' normalization approach uses a five year average (calendar years

2004 through 2008) of actual payments for injury and damages claims (four years in the case of AmerenIP),[22] adjusted for inflation using the consumer price index ("CPI"). The only point of contention with respect to the AIUs' normalization approach is the use of an inflation factor in calculating the historical average.[23] Elimination of an inflation factor would reduce the total electric revenue requirement by $673,000 and the gas revenue requirement by $129,000. (IIEC Ex. 3.0 (Meyer Dir.), p. 8.)

IIEC is the only party to argue that the AIUs' normalization method should not include an inflation component. IIEC claims that the use of an inflation factor is improper because "[t]he absence of an inflation factor has not caused these fluctuations. Instead, the logical assumption is that the fluctuation in these charges would be a function of the number of claims settled during and calendar year and the size of the claims settled in the year." (Id.) Mr. Meyer misses the point. No one disputes that injuries and damages expense fluctuates from year to year. Smoothing out these fluctuations is accomplished through the use of a four or five year average. (Ameren Ex. 30.0 (Wichmann Reb.), p. 3.) But simply calculating a mathematical average of historical claims experience fails to account for the fact that today's dollars purchase fewer goods and services than dollars in years past. The reason is inflation. As Mr. Meyer acknowledges, inflation is the rise in the general level of prices over a period of time. (Tr. 559.)

[22] In the AIUs' last rate case, Docket 07-0585/0590 (cons.), the Commission found that AmerenIP's 2005 injuries and damages expense was unusually high and should therefore not be used in a normalization calculation. Consistent with this prior determination, the AIUs excluded 2005 in AmerenIP's normalization calculation. (Ameren Ex. 3.0 (Wichmann Dir.), p. 10.)

[23] Staff adjusted the AmerenIP electric injuries and damages calculation to remove expenses associated with hazardous materials, which are recovered separately under the hazardous materials adjustment clause ("HMAC"). (ICC Staff Ex. 1.0 (Ebrey Dir.), pp. 29-30.) The AIUs agree with this adjustment. (Ameren Ex. 30.0 (Wichmann Reb.), p. 3.)

When inflation rises, a dollar purchases fewer goods and services. (Tr. 559-60.) Assuming a positive level of inflation between 2004 and 2008, a dollar would be worth less today than it was worth in 2004. (Tr. 560.) Consequently, all other things being equal, if it cost $100 to settle a claim in 2004, it would cost more than $100 to settle that same claim in 2010, when rates in this proceeding go into effect. (Tr. 561.)

The AIUs' normalization calculation properly recognizes the affect of inflation. IIEC's adjustment does not. As noted by Mr. Stafford, the inflation adjustment has not been opposed by Staff and is consistent with the treatment of normalized storm expense (another volatile expense analogous to injuries and damages) that Staff and AG/CUB have endorsed in these proceeding. (Ameren Ex. 51.0 2d Rev. (Stafford Sur.), p. 25; see supra Sec. III.B.6.) By ignoring inflation, IIEC's calculation understates injuries and damages expense and should be rejected.

12. Overall Reasonableness of O&M Expenses

In prior rate proceedings, parties have expressed concern to the Commission that the AIUs have not been effective in controlling certain of their O&M expense levels. To address those concerns in these rate cases, the AIUs took additional steps to confirm that their recently incurred operation and maintenance ("O&M") expenses are reasonable. In connection with filing these rate cases, the AIUs retained Concentric Energy Advisors, a management consulting and economic advisory firm focused on the North American energy and water industries, to compare the AIUs' O&M expenses (electric and gas companies) to those of other utilities. Mr. Ronald J. Amen, a Vice President with Concentric, used the peer-group approach to benchmark the AIUs' O&M expenses against those of other utilities. Specifically, Mr. Amen took the most recent data available to Concentric – FERC account level data for calendar year 2007 obtained from FERC Form 1 and Form 2 filings – analyzed the data through a series of objective, comprehensive studies by benchmarking the AIUs' actual O&M expenses against other electric, gas, and combination utilities.

The results of his sixteen peer-group benchmarking studies led Mr. Amen to conclude that the AIUs' O&M expenses, including their A&G expenses, are on average lower than the majority of other gas, electric and combination utilities. Indeed, these studies, comprehensive in number and scope, demonstrated that the AIUs effectively controlled O&M expenses because they consistently performed better than their peers on a cost per customer basis. Based on these results, the parties – and the Commission – can take comfort that the AIUs have been effective in controlling their O&M expenses at reasonable levels.

a. *The Peer-Group Benchmarking Approach Appropriately Evaluates the Reasonableness of the AIUs' O&M Expenses.*

Concentric employed the peer-group benchmarking approach because such studies are objective, straight-forward, verifiable, replicable and relevant to the AIUs. (Ameren Ex. 32.0 (Amen Reb.), p. 6.) These types of studies are also often filed with regulatory commissions as an indicator of the reasonableness of a company's expenses. (Ameren Ex. 32.0 (Amen Reb.), p. 4.) Indeed, Mr. Amen's studies amply illustrate why this approach should be relied upon by the Commission in these proceedings as they did in the last rate case. (Ameren Exs. 5.0E Rev., 5.0G Rev. (Amen Dir.), p. 5.) First, Mr. Amen's studies are objective. They include all costs for all companies that meet the parameters of the peer group being examined. (Ameren Ex. 32.0, p. 6.) In other words, no costs or companies are excluded subjectively or arbitrarily; if a company meets the parameters of the study, it is included. (Id.)

Second, Mr. Amen's studies are straightforward. By viewing the results of the studies, the Commission can easily understand how each of the AIUs and the combined AIUs compare to other utilities. (Ameren Ex. 32.0, p. 7.) Indeed, the results of each of the studies are graphically presented in an accessible exhibit. (Id.) If one or more of the AIUs' performance did not compare well to its peers, the study (and the corresponding exhibit) would clearly reflect that fact. (Id.)

Third, Mr. Amen's studies are easily verifiable and replicable. He used information from the Form 1 and 2 annual reports filed with the Federal Energy Regulatory Commission ("FERC") by each of the peer group companies. (Ameren Ex. 32.0, p. 7.) He compiled this information and reported it without adjustment. (Id.) Therefore, the information contained in the peer-group benchmarking studies can be easily recreated by examining each company's annual report to the FERC. (Id.) And once compiled, the information can be used to replicate each of the studies. (Id.)

Fourth, Mr. Amen's benchmarking studies are relevant to the AIUs and these proceedings. Through the use of relevant parameters, a researcher can create peer groups that consist of companies with similar operating characteristics. (Ameren Ex. 32.0, p. 7.) Comparisons can then be made as to the cost performance of each of the companies that meet the characteristic or parameter being studied. (Id.) Mr. Amen created and compared peer groups consisting of gas, electric, and combined utilities, as the AIUs fit these parameters. (Id., p. 8.) He also benchmarked Midwestern gas and electric companies (the location of the AIUs) as well as companies of sizes comparable to the AIUs and comparable breath of services (e.g., whether the utility owns generation.) (Id.) By accounting for all of these characteristics in various peer groups, Mr. Amen's studies aptly illuminate the AIUs' cost performance.

Finally, Mr. Amen's peer-groups consist of a sufficient number of peers, which serve as the basis to evaluate the AIUs' cost performance. It is uncontested that a peer group consisting of roughly ten peers is adequate; the peer groups in Mr. Amen's studies ranged from 9 to 205 peers. (Ameren Ex. 32.0 (Amen Reb.), p. 8.) While there is no single peer group containing companies with all of the same attributes against which to compare the AIUs' cost performance, (Ameren Ex. 71.0 (Amen Sur.), p. 9), Mr. Amen constructed sixteen different peer groups, taking account of differences associated with size, geographic location, and the fact that the AIUs own no regulated generation. (Id.; Tr. 429-30.) Collectively, Mr. Amen's peer-groups adequately account for the operating characteristics of the AIUs, and include more than a sufficient number of peers from which Mr. Amen could make robust and relevant findings about the AIUs' cost performance. (Ameren Ex. 71.0, pp. 9-10.)

b. *The Peer Group Benchmarking Studies Demonstrate that the AIUs' Actual O&M Expenses Were Reasonable.*

Mr. Amen first compared the AIUs' A&G expenses to those of several peer groups through ten benchmarking studies. (Ameren Exs. 5.0E Rev., 5.0G Rev. (Amen Dir.), p. 4.) These studies are explained through Mr. Amen's direct testimony, marked Ameren Exhibit 5.0E Rev. & 5.0G Rev., and the results are depicted in graph form in Ameren Exhibits 5.1-5.11.

For his studies, Mr. Amen collected total A&G expense amounts and customer counts for peer companies. (Ameren Ex. 5.0E Rev., 5.0G Rev. (Amen Dir.), p. 4.) The costs included in the ten benchmarking analyses are unadjusted and reflect the amounts as reported in all peer companies' respective FERC Form 1 and 2 annual reports. (Id. at p.7.) The FERC Form 1 and 2 annual reports provide a sound basis for cost comparison as utilities adhere to the FERC Uniform System of Accounts prescribed for public utilities. (Id.) Mr. Amen took this information and unitized the costs on a per-customer basis to compare the AIUs' A&G expenses per customer to those of other utilities.[24] (Id., p. 4.) Mr. Amen performed these analyses for natural gas utilities, electric utilities, and combination utilities (i.e., those with both electric and gas operations). (Id.) He also prepared ten different iterations of the analyses to make the peer group of utilities more comparable to the characteristics of the AIUs. (Id., pp. 4-5.)

Mr. Amen's ten studies show that the AIUs' A&G expenses compare favorably to their peers with similar operating characteristics. Mr. Amen included the following peer groups in his A&G expenses benchmark analysis: (1) electric utilities, (2) electric utilities in the Midwest, (3) electric utilities that own no generation, (4) electric utilities in the Midwest that own no generation, (5) similarly sized electric utilities that own no generation, (6) combination utilities, (7) combination utilities that owned no generation, (8) gas utilities, (9) gas utilities in the Midwest, and (10) similarly sized gas utilities in the Midwest. (Id., pp. 9-16.) For nearly all of these peer groups, the AIUs – both individually and collectively – operated at or below the mean and/or median costs of their peers. (Id.; Ameren Exs. 5.1-5.11.) Thus, these peer-group benchmarking studies demonstrate that the AIUs have effectively controlled A&G expenses during calendar year 2007, and the AIUs' A&G expenses per customer compare favorably to those of other electric, gas, and combination utilities. (Id., p. 16.)

[24] The AIUs' A&G expenses for this study represented the A&G expenses incurred directly by the AIUs as well as those incurred on behalf of the AIU. (Id., p. 5.)

After presenting peer-group benchmarking studies for A&G expenses, Mr. Amen expanded his analysis to include studies of the AIUs' total O&M expenses. The results of six additional peer-group benchmarking studies are explained through Mr. Amen's rebuttal testimony, marked Ameren Ex. 32.0, and depicted in graph form in Ameren Exhibits 32.1-32.6. Unlike Mr. Fenrick's alleged "total O&M" study presented in these proceedings, Mr. Amen's six O&M studies analyzed *all* relevant O&M costs (including transmission, distribution, customer care and A&G expenses) with the exception of total electric power production and total gas production expenses. (Ameren Ex. 32.0., p. 3.) And like his A&G studies, Mr. Amen's O&M studies compared the AIUs' O&M expenses per customer to several similarly situated peer groups: (1) electric utilities, (2) gas utilities, and (3) combined utilities. (Ameren Ex. 32.0 (Amen Reb.), at pp. 12-13.)

Not surprisingly, the total O&M studies confirmed what Mr. Amen had found with respect to the A&G studies: the AIUs – both individually and collectively – performed at or below the mean and median expenses of their peers. (Id.) For example, Ameren Exhibit 32.1 shows the results of the study of the total electric O&M per customer for each of the electric utilities which filed a Form 1 with the FERC; the AIUs individually and collectively perform at or below the mean and the median of the 145 companies under review. (Ameren Ex. 32.0 (Amen Reb.), p.12; Ex. 32.1.) As shown by Ameren Ex. 32.1, the peer group mean was $403.94 per customer, while the median was $388.45; the AIUs' total O&M costs per customer was below both the mean and median at $348.64.[25]

[25] The individual AIUs' total cost per customer was $314.65 for Ameren IP, $374.39 for Ameren CILCO, and $388.45 for AmerenCIPS.

The results for the gas utilities were very similar. As Exhibit 32.2 shows, Ameren IP, AmerenCILCO and the collective AIUs were all well below both the mean and the median of the peer group, which consisted of 192 gas companies. (Ameren Ex. 32.0 (Amen Reb.), p.12; Ameren Ex. 32.2.) The only slight variance in performance related to AmerenCIPS, which when compared to gas only companies fell below the mean, but slightly higher than the median of the peer group.

Ameren 32.3 shows the results of the benchmarking study of combined total electric and gas companies' O&M expenses. In this comprehensive study, the AIUs ranked well below both the mean and the median of the peer group, which consisted of 42 combination utilities. (Ameren Ex. 32.0 (Amen Reb.), p.13; Ameren Ex. 32.3.) The mean was $353.00 per customer and the median was $347.95 per customer; the AIUs collective cost per customer was $288.09.

Finally, to compare labor cost efficiency among combination utilities like the AIUs, Mr. Amen studied the number of customers per employee. This metric serves as a check of the efficiency with which each company provides service to its customers. (Ameren Ex. 32.0 (Amen Reb.), p. 13.) In this study, the AIUs compared very favorably to the peer group of other combination utilities. The AIUs, individually and collectively, ranked between 4th and 14th out of a peer group of 89 electric and diversified utilities. (Id., pp. 13-14.) AmerenIP had 888 customers per employee while AmerenCIPS had 864, the combined AIUs had 835 and AmerenCILCO had 701. (Ameren Ex. 32.0 (Amen Reb.), p. 14.) The mean of the peer group was 446 and the median was 382. (Id.)

c. *Conclusion*

Each of the sixteen peer group benchmarking studies provides insight as to how the AIUs' O&M expenses compare to their peers. And each of the sixteen studies demonstrates that the AIUs consistently perform better than average on a cost per customer basis than their peers. (Ameren Exs. 5.1-5.11; 32.1-32.6.) While the results of the benchmarking analyses conducted by Concentric are just one aspect of the overall picture confirming the reasonableness of the AIUs' test year O&M expenses, they are something that the Commission can, and should, consider when approving the AIUs rate increase requests.

13. Other

a. *Cities' Recommendations – AmerenIP*

AmerenIP provides electric service to approximately 626,000 electric customers over 40,000 miles of electrical circuits and 427,000 gas customers over 8400 miles of distribution mains in hundreds of incorporated municipalities across 15,000 square miles in central, east central and southern Illinois. Within AmerenIP's service territories, several communities have intervened in this proceeding: the Cities of Champaign, Urbana, Decatur and Bloomington, Illinois and the Town of Normal, Illinois (collectively, the "Cities"). In their testimony, the Cities make the following recommendations to the Commission: (1) monitor AmerenIP's annual maintenance and system improvement investments; (2) direct AmerenIP to identify, prioritize and address the need to replace aged assets on a case-by-case basis; (3) direct AmerenIP to expedite its correction of existing NESC violations; and (4) continue to monitor the status of unresolved Liberty Report recommendations. (Cities Ex 3.0 (Brodsky Reb.), p. 13.)

The Commission should reject each of the Cities' recommendations as unnecessary and imprudent. First of all, AmerenIP already provides Staff, on an annual basis, with data concerning its capital and O&M expenditures. Introducing yet another level of monitoring of AmerenIP's expenditures is an unnecessary exercise and very likely a waste of resources. Despite the Cities' claims, AmerenIP's investment in its systems has not declined, nor is the reliability of its service threatened. Secondly, AmerenIP already reports the book depreciation values of its distribution assets, as allowed under Subsection 411.120(b)(3)(G) of 83 Ill. Admin. Code. Requiring AmerenIP to identify and report on the physical age of each distribution asset is neither required nor warranted. The AIUs already regularly inspect the condition of their electric distribution assets. The method of age-reporting proposed by the Cities does not allow the AIUs (or the Commission) to predict the future reliability of an asset. Thirdly, the AIUs already have agreed with Staff on a timetable for inspecting their distribution networks and resolving NESC violations. Requiring the AIUs to arbitrarily expedite NESC corrective actions in any one area of its operations—or at the expense of undertaking other capital investments and maintenance projects concerning AmerenIP's own infrastructure—would be inappropriate.[26] The Staff and the AIUs are in agreement that the Cities' recommendations are unnecessary or inappropriate.

The Cities' suggestion that AmerenIP's investment in its electrical systems has been in decline is simply inaccurate. Except for a brief drop in spending in 2007 after a storm-related spike in expenditures in 2006, AmerenIP's capital investments and O&M expenditures have trended upwards since the AIUs acquired the utility in 2004. (Ameren Ex. 35.0 (Justice Reb.), p. 15; ICC Staff Ex. 24.0R (Rockrohr Reb.), p. 14.) Indeed, Staff is fully aware that AmerenIP's

[26] The AIUs already regularly update the Commission on their progress in implementing the recommendations set forth in the Liberty Report. The Cities' recommendation for continued monitoring is redundant.

investment and expense is not declining, since AmerenIP already provides data on its capital and O&M expenditures to Staff on an annual basis. (Ameren Ex. 66.0 (Justice Sur.), p. 7; ICC Staff Ex. 24.0R, p. 14.) No further independent investigation or monitoring of AmerenIP's expenditures by the Commission is necessary. Staff agrees: "[Staff] does not believe [Cities'] recommendation[] that the Commission investigate why AmerenIP has been reducing its maintenance investment is warranted." (ICC Staff Ex. 24.0R, pp. 14-15.)

The Cities complain that "AmerenIP's investments have declined significantly from 2006." (Cities Ex. 3.0, p. 8.) But the Cities admit that AmerenIP's capital investments in maintenance and system improvements have increased between 2007 and 2009. (Tr. 679-80.) Equally as important, the Cities ignore critical facts that belie their position. First, they ignore that AmerenIP's expenditures, both its capital investments and O&M expenses, spiked in 2006 because of catastrophic summer and winter storms. (Ameren Ex. 35.0, p. 15; ICC Staff Ex. 24.0R, p. 14.) Second, the Cities ignore the fact that AmerenIP invested heavily in its distribution infrastructure in 2004-2006 after Ameren acquired the utility. (Tr. 680-84.) Indeed, the Cities' own witness Mr. Brodsky, who was hired by the Cities to develop and evaluate Ameren's audit of the Illinois Power's electrical distribution systems, acknowledges that Ameren spent millions of dollars on system improvements to correct and upgrade those systems, including projects specifically requested by the Cities of Champaign and Urbana that were identified and designed by Mr. Brodsky. (Tr. 682-83.)

The Cities further complain that AmerenIP's investments "fall significantly behind that of AmerenCILCO and AmerenCIPS." (Cities Ex. 3.0, p. 8.) But the data relied on by the Cities concerning the AIUs' capital investments in maintenance and system improvements shows that, in the 2008 test year, the total capital dollars spent per customer were practically identical: $108.09 for Ameren CILCO; $107.98 for AmerenCIPS; and $105.00 for AmerenIP. (Id., p. 7.) Equally as important, the Cities again fail to consider critical facts. First, they do not consider the typical fluctuations that occur in a utility's amount of investment on an annual basis because of extreme weather, circuit inspection findings, completion time of projects and system enhancement needs. (Ameren Ex. 66, p. 7.) Second, the Cities do not consider the unique characteristics of the individual utilities, such as customer density, the makeup of the customer classes, or whether the utility services predominantly urban or rural areas, all of which impact the per customer investment levels of the individual utilities. (Tr. 688-90.) Third, they fail to consider other indicators of the reliability of a utility's service and systems, such as the utility's SAIDI, CAIDI or CAIFI ratings or data concerning the utility's worst performing circuits. (Tr. 686-88.) Even if the Cities were correct that AmerenIP's investments in its systems are in decline or somehow "are lagging" (Cities Ex. 3.0, p. 13.) behind the other utilities, the Cities have failed to conduct a sufficiently reliable study to identify AmerenIP's appropriate level of capital investment per customer or assess the overall reliability of AmerenIP's distribution network. It would be inappropriate to conclude on this record that AmerenIP's investments are lacking or that its service is unreliable.

The Cities' recommendations for the Commission regarding AmerenIP's reporting of aging assets and expediting of NESC violations are similarly flawed and should be rejected. As mentioned above, the AIUs utilize book depreciation, rather than actual physical age, when reporting the age of existing distribution assets. (ICC Staff Ex. 24.0R, pp. 15-16.) Whether an asset has exceeded its book depreciation is not necessarily determinative of the asset's reliability. (Ameren Ex. 35.0, p. 16.) As Staff witness Mr. Rockrohr points out, "well-maintained distribution facilities/equipment can last well beyond the facility's assigned depreciable life." (ICC Staff Ex. 24.0R, p. 17, lines 360-61.) The AIUs utilize a comprehensive Circuit Inspection Program to identify and correct potential performance issues with their distribution assets. (Ameren Ex. 35.0, p. 16.). As Mr. Rockrohr notes, "[t]he method of age-reporting that the utility uses is not nearly as significant as the utility's inspection and maintenance practices." (ICC Staff Ex. 24.0R, p. 17, lines 362-63.) In any event, as Cities know, the AIUs do not have physical installation records for a significant portion of its distribution poles, transformers and conductors/cables, making it nearly impossible for AmerenIP to report the physical age of its assets. (Ameren Ex. 35.0, p. 16.)

Nor should the AIUs arbitrarily expedite the correcting of NESC violations in AmerenIP's service territories. The AIUs already have agreed with Staff to a NESC Corrective Action Plan for inspecting the AIUs' distribution circuits and resolving NESC violations. (ICC Staff Ex. 24.0R, pp. 17-18.) The AIUs already provide Staff with quarterly reports concerning their efforts to identify and correct NESC violations. (Id.) It would be inappropriate to deviate from the current plan in place to expedite corrections in any one area of the AIUs' operations or at the expense of other essential investments in AmerenIP's own infrastructure. Staff concurs that "AIU's completion of corrections through use of [their] NESC Corrective Action Plan remains the best approach for correcting all existing violations." (ICC Staff Ex. 24.0R, p. 19.)

The Cities ask the Commission to order actions that are unnecessary, unwarranted and waste of the AIUs' and the Commission's time and resources. AmerenIP's capital expenditures and O&M expenses are not significantly declining. Nor are AmerenIP's aging assets in danger of failing if the AIUs do not identify the physical age of all of their distribution assets. Nor is the reliability of AmerenIP's network threatened by the AIUs' current timetable for inspecting and resolving NESC safety violations. The AIUs are taking the prudent and necessary actions to ensure that AmerenIP's service remains adequate, safe and reliable. The processes already in place to ensure that level of service are efficient and cost-effective. It would be imprudent for AmerenIP to incur, and pass along to the Cities' own constituents and other AmerenIP customers, additional costs to perform work that is redundant, ineffective or non-essential at this time. Staff agrees. Accordingly, the Commission should reject the Cities' recommendations.

D. Recommended Operating Income/Revenue Requirement

1. Electric

The AIUs presented schedules showing, for each of the gas and electric AIUs, the operating revenues, expenses, and income at present and proposed rates for the test year. Staff and other parties proposed adjustments to the AIUs' proposed operating statements as discussed below. The proposed operating income statement for the AmerenCILCO, AmerenCIPS and AmerenIP electric utilities are shown on Schedule 1 of Appendix A, B, and C, respectively.

2. Gas

The proposed operating income statement for the AmerenCILCO, AmerenCIPS and AmerenIP gas utilities are shown on Schedule 1 of Appendix D, E, and F, respectively.

IV. COST OF CAPITAL/RATE OF RETURN

A. Overview

As noted by the Commission in Dockets 06-0070, *et al.* (cons.):

> A company utilizes various types of investor-supplied capital to purchase assets and operate a business. Utilities typically rely upon long-term debt and common equity, and in some instances preferred stock and short-term debt, to purchase assets and fund operations. The costs of different types of investor-supplied capital vary depending upon a multitude of factors, including the risk associated with the investment. As a result, the proportion of the different types of capital, also known as the capital structure, when combined with the costs of each different type structure affects the overall or weighted average cost of capital, which is the rate of return a utility is authorized to earn on its net original cost rate base.

(Order, p. 87.) Like the Commission, the AIUs rely on the cost of capital standard to determine their requested fair rate of return. (See AmerenCILCO Ex. 13.0G (O'Bryan Direct); AmerenCIPS Ex. 13.0E Rev. (O'Bryan Dir.); AmerenIP Ex. 13.0E Rev. (O'Bryan Dir.); Ameren Ex. 28.0 (Nickloy Reb.); Ameren Exs. 37.0-37.4 Rev. (O'Bryan Reb. and supporting exhibits); Ameren Ex. 59.0 (O'Bryan Sur.); Ameren Ex. 60.0 (Nickloy Sur.) This cost, which can be determined from the overall rate of return or weighted average cost of capital, must produce sufficient earnings/cash flow when applied to the respective AIUs' rate base at book value to enable the AIUs' to maintain the financial integrity of their existing invested capital, maintain their creditworthiness, attract sufficient capital on competitive terms to continue to provide a source of funds for continued investment, and enable the Companies to continue to meet the needs of their customers. (AmerenCILCO Ex. 13.0G, p.3; AmerenCIPS Ex. 13.0E, p. 3.)

Beyond the fact that these standards are effectively mandated by Bluefield Water Works & Improvement Co. v. Public Service Commission of West Virginia, 262 U.S. 679 (1923) and Federal Power Commission v. Hope Natural Gas Company, 320 U.S. 391 (1944), meeting these requirements is necessary in order for a company to effectively meet the utility services requirements of its customers and provide an adequate and reasonable return to its investors, debt holder and equity holder alike. (AmerenCILCO Ex. 13.0G, p. 3.) The assets owned by the AIUs are employed in meeting their customers' utility services requirements. (Id.) These assets exist and are available for this purpose only because investors have entrusted their funds with the respective AIU and deemed an investment in the securities issued by that Company to be sound and capable of providing a competitive return. (Id.) A utility must maintain its creditworthiness in order to continue to attract capital on a competitive basis. (Id.) This is important to assure future opportunities for the AIUs to replace capital and various securities which must be refinanced in the future at reasonable cost. (Id.) Also, the ability of the AIUs to attract new capital on competitive terms is critical in order for the Companies to continue to replace and upgrade facilities used to meet the utility services needs of their customers. (Id., pp. 2-3.) It is under this framework that the AIUs propose their respective capital structures, cost of debt and cost of equity, and overall rate of return.

B. Capital Structure

1. Central Illinois Light Company (CILCO)

a. *Preferred Stock Balance – Immaterial Difference*

According to AmerenCILCO, its March 31, 2009 preferred stock balance is $18,893,567. (AmerenCILCO Ex. 13.0G (O'Bryan Dir.), p. 6; Ameren Ex. 13.1; Ameren Ex. 37.1.) This number reflects the carrying value or net proceeds amount of AmerenCILCO's preferred stock as found in the embedded cost calculation for this component of capitalization. (AmerenCILCO Ex. 13.0G, p. 6.) Staff adjusted the discount expense for AmerenCILCO's outstanding preferred stock issues, which Staff maintains had a small effect on the balance and did not affect the embedded cost of preferred. (ICC Staff Ex. 5.0 (Phipps Dir.), p. 18, n.29.) As a result, Staff's adjusted balance for AmerenCILCO's preferred stock equals $18,893,282. (ICC Staff Ex. 5.0, p. 18, n.29; ICC Staff Ex. 5.0, Sch. 5.04.) This adjustment represents an immaterial difference.

b. *Short-Term Debt Balance - Resolved*

AmerenCILCO maintains, and Staff does not dispute, that the balance of AmerenCILCO's short-term debt equals $32,017,993. (AmerenCILCO Ex. 13.0G (O'Bryan Dir.), p. 5; ICC Staff Ex. 5.0 (Phipps Dir.), p. 13; ICC Staff Ex. 19.0 (Phipps Reb.), p. 1.)) This balance was calculated pursuant to the formula set forth in the Illinois Commerce Commission Rate of Return Instructions Section 285.4020 Schedule D-2: Cost of Short-term Debt (b-4) (as outlined on AmerenCIPS Ex. 13.3). (AmerenCILCO Ex. 13.0G, p. 5.)

c. *Long-Term Debt Balance – Immaterial Difference*

With respect to AmerenCILCO's long-term debt, Mr. O'Bryan testified that the balance, $271,492,364, is the total carrying value of all of AmerenCILCO's long-term debt (first mortgage bonds and pollution control bonds) using the net proceeds method, as outlined in AmerenCILCO Ex. 13.2. (AmerenCILCO Ex. 13.0G (O'Bryan Dir.), p. 5.). Ms. Phipps testified that this balance should be $271,691,990. (ICC Staff Ex. 5.0 (Phipps Dir.), p. 15.) This adjustment represents an immaterial difference.

d. *Common Stock Balance –Resolved*

AmerenCILCO and Staff agree that AmerenCILCO's March 31, 2009 common equity balance is $249,457,171. (AmerenCILCO Ex. 13.0G (O'Bryan Dir.), p. 6; Ameren Ex. 13.1; Ameren Ex. 37.1; ICC Staff Ex. 5.0 (Phipps Dir.), pp. 18-19.)

2. Central Illinois Public Service (CIPS)

a. *Preferred Stock Balance – Resolved*

AmerenCIPS and Staff agree that AmerenCIPS's balance of preferred stock is $48,974,984, which is the carrying value or net proceeds amount of AmerenCIPS's preferred stock as found in the embedded cost calculation for this component of capitalization. (AmerenCIPS Ex. 13.0E Rev. (O'Bryan Dir.), p. 5; Ameren Ex. 13.1; Ameren Ex. 37.1; ICC Staff Ex. 5.0 (Phipps Dir.), p. 23.)

b. *Short-Term Debt Balance - Resolved*

AmerenCIPS maintains and Staff does not dispute that AmerenCIPS' short-term debt balance equals $58,096,936. (See Ameren Ex. 37.0 Rev. (O'Bryan Reb.), p. 2; Ameren Ex. 37.1; ICC Staff Ex. 5.0 (Phipps Dir.), pp. 13, 19; ICC Staff Ex. 5.0, Sch. 5.02.) This balance was calculated pursuant to the formula set forth in the Illinois Commerce Commission Rate of Return Instructions Section 285.4020 Schedule D-2: Cost of Short-term Debt (b-4) (as outlined on AmerenCIPS Ex. 13.3). (AmerenCIPS Ex. 13.0E Rev. (O'Bryan Dir.), p. 5.)

c. *Long-Term Debt Balance – Resolved*

Mr. O'Bryan testified that AmerenCIPS' balance of long-term debt, $397,043,827, is the total carrying value of all of CIPS' long-term debt (first mortgage bonds and pollution control bonds) using the net proceeds method. (AmerenCIPS Ex. 13.0E Rev. (O'Bryan Dir.), p. 5.) Staff argues that AmerenCIPS' balance of long-term debt should be $397,751,866, which reflects an adjustment to remove any incremental cost increase due to AmerenCIPS' decision to refinance a $67 million, five-year intercompany promissory note bearing 4.7% with $61.5 million in 30-year bonds bearing a 6.7% interest rate. (ICC Staff. Ex. 5.0 (Phipps Dir.), p. 21.) Mr. O'Bryan previously testified in Docket Nos. 07-0585 – 07-0590 (cons.) that AmerenCIPS was justified in refinancing the 4.70% note. (Ameren Ex. 37.0 Rev. (O'Bryan Reb.), p. 3.) However, AmerenCIPS accepted Ms. Phipps' position on this issue for the purposes of this case only. (Id.; Ameren Ex. 37.1, p. 2.)

d. *Common Stock Balance – Resolved*

AmerenCIPS's December 31, 2008 common equity balance is $478,676,606. (AmerenCIPS Ex. 13.0E Rev. (O'Bryan Dir.), p. 5; Ameren Ex. 13.1; Ameren Ex. 37.1.) Staff agrees with, and no other party contests, AmerenCIPS's proposed common equity balance. (ICC Staff Ex. 5.0 (Phipps Dir.), p. 23.).

3. Illinois Power Company (IP)

a. *Preferred Stock Balance – Resolved*

AmerenIP and Staff agree that AmerenIP's balance of preferred stock is $45,786,945, which is the carrying value or net proceeds amount of IP's preferred stock as found in the embedded cost calculation for this component of capitalization. (AmerenIP Ex. 13.0E Rev. (O'Bryan Dir.), p. 6; Ameren Ex. 13.1; Ameren Ex. 37.1; ICC Staff Ex. 5.0 (Phipps Dir.), pp. 31-32.)

b. *Short-Term Debt Balance – Resolved*

AmerenIP maintains that its balance of short-term debt is $10,404,002. (AmerenIP Ex. 13.0E Rev. (O'Bryan Dir.), p. 5.) Staff argues that AmerenIP's short-term balance should be adjusted to $10,791,502 to reflect an adjustment wherein the short-term debt calculation does not subtract cash from short-term debt. (ICC Staff Ex. 5.0 (Phipps Dir.), p. 24.) Ms. Phipps argued on direct that, for the one month during the short-term debt measurement period that AmerenIP had short-term debt outstanding, AmerenIP subtracted "excess cash" from short-term debt. (Id.) While Ms. Phipps admitted that AmerenIP's calculation does not affect

AmerenIP's overall cost of capital, she argues that the calculation was improper because it is not a part of short-term indebtedness. (Id.) Ms. Phipps further argued that the short-term debt calculation adopted by the Commission in AmerenIP's 2007 rate case was based on very specific, unique circumstances that do not apply in the instant case. (Id.)

However, AmerenIP's short-term debt balance was calculated pursuant to the formula set forth in the Illinois Commerce Commission Rate of Return Instructions, Section 285.4020 Schedule D-2: Cost of Short-term Debt (b-4) (as outlined in AmerenIP Exhibit 13.3). (AmerenIP Ex. 13.0E Rev. (O'Bryan Dir.), p. 5.) The Commission's approach from recent rate proceedings was followed, which calculates the amount of short-term debt in the capital structure by taking an average of month-end short term debt balances six months prior to and following the capital structure measurement date. (Id.) This approach aligns the measurement period with a midpoint that coincides with the measurement date of the long-term capital structure components. (Id.) In order to follow this approach, construction work in progress ("CWIP") balances for the months ended April 2009 through September 2009 and short-term debt balances for the months ended May 2009 through September 2009 were estimated. (Id., pp. 5-6.) The estimated balances were updated as they became available. (Id., p. 6.)

c. *Long-Term Debt Balance – Contested*

AmerenIP maintains that its balance of long-term debt is $1,357,044,075, which is the total carrying value of all of the Company's long-term debt (first mortgage bonds and pollution control bonds) using the net proceeds methods. (AmerenIP Ex. 13.0E Rev. (O'Bryan Dir.), p. 5; Ameren Ex. 37.1, p. 3.) However, Staff argues that AmerenIP's long-term debt balance should equal $1,307,983,675, to reflect a reduction in the principal amount of AmerenIP's October

2008 debt issuance to from $400 million to $350 million. (ICC Staff Ex. 5.0, p. 25.) Staff argues that the reduction is proper because AmerenIP was simultaneously contributing surplus funds to and borrowing from the money pool at the time it issued the $400 million in secured notes. (Id.) Ms. Phipps testified that such transactions were unnecessary given the Commission's rules governing money pools require that money pool borrows repay the principal amount of money pool loans on demand of the lending utility. (Id.) She argues that, rather than issue $400 million in bonds, AmerenIP should have recalled its money pool loan and issued long-term debt in an amount sufficient to repay its credit facility borrowings. (Id.) Thus, she proposes a reduction in the principal amount of the 9.75% bonds and claims that, absent this adjustment, AmerenIP customers would pay a 9.75% interest rate on $50 million bonds, the proceeds of which AmerenIP allegedly did not require for its electric and gas delivery operations. (Id., pp. 25-26.)

However, as Mr. Nickloy argues in his rebuttal, Ms. Phipps' adjustment to exclude a portion of the principal amount of AmerenIP's long-term debt issuance is unwarranted. (Ameren Ex. 28.0 (Nickloy Reb.), p. 5.) First, AmerenIP's long-term debt issuance was not impacted by its temporary short-term debt with an objective of maintaining an appropriate level of available liquidity. (Id.) AmerenIP sized the debt issuance to retire its own short-term debt with an objective of maintaining an appropriate level of available liquidity. (Id.) Liquidity consists of available cash balances and available borrowing capacity under committed bank facilities and ensures the company can fully and timely meet all of its payment and collateral posting requirements. (Id.) Prior to its recent ratings upgrade, AmerenIP had sub-investment grade, or "junk" issuer credit ratings which make it subject to material cash collateral calls from its counterparty suppliers. (Id.) These collateral demands must be made very quickly once demand has been made and the consequences of not making the posting as contractually agreed can result in an event of default. (Id.) These collateral demands can create sizable, volatile, unpredictable and immediate needs for cash thus requiring meaningful liquidity resources. (Id., pp. 5-6.)

Mr. Nickloy also noted that these obligations must be met regardless of the timing and amount of the company's incoming cash flows. (Id., p. 6.) At the time of the issuance, the money pool loan to AmerenCIPS was simply a temporary use of funds which would have otherwise been maintained as highly liquid short-term investment as a liquidity reserve. (Id.) Unfortunately, AmerenIP does not have the benefit of hindsight (as does Ms. Phipps' historical cash flow analysis) available to it in ensuring AmerenIP has adequate liquidity reserves to fund future cash requirements. (Id.) Not having sufficient liquidity to fund the operations of utility is a worst case outcome, with adverse consequences for customers, employees and investors.

At the time of this debt financing, AmerenIP was fully utilizing its capacity under its two bank facilities and had to further meet its short-term borrowing requirements through borrowings from Ameren. (Id.) Another key factor impacting the need for this financing and the requirement to improve AmerenIP's liquidity position was the condition of the capital markets and bank markets. (Id.) During this time, the capital markets were in a high state of distress and the bank markets were effectively closed. (Id.) Lehman Brothers filed for bankruptcy the month before and the markets were rife with rumors around the potential failure of other financial institutions including, among others, Citibank, Wachovia and Goldman, Sachs. (Id.) Too, there was well-founded concern about financial institutions generally because of the "interconnectedness" of these firms and a lack of knowledge around how much exposure they had to one another. (Id.) After its bankruptcy filing, Lehman Brothers was no longer funding loan requests under these facilities and many feared others would follow. (Id., p. 7.) At the time of its bankruptcy filings, Lehman Brothers represented $71 million of the $1 billion in credit facilities AmerenIP could directly access (under its $350 million of borrowing sublimits). (Id.) The other three institutions listed above represented a combined total of approximately $265 million under these facilities. (Id.) At the hearing, Ms. Phipps acknowledged these circumstances existed in the financial market at the time. (Tr. 260.) Only with the benefit of hindsight can one argue that the liquidity risk that this environment represented was not worth acting upon. (Ameren Ex. 28.0 (Nickloy Reb.), p. 7.)

Mr. Nickloy testified that the debt capital markets were also severely distressed. (Id.) Many issuers could not even access debt capital, and those that could were faced with very high investor return requirements (as evidenced by higher credit spreads). (Id.) The timing and level to which these markets for capital would improve or re-open was highly uncertain, and there was an acute absence of any comfort that things would not get worse. (Id.) Adding to this environment was the fact the AIUs' bank facilities were scheduled to expire in January 2010 with no assurance that the bank markets would improve and permit the extension or renewal of these facilities. (Id.) Liquidity was at a premium and IP took the prudent step of completing a refinancing in order to improve its liquidity position and ensure that it would have sufficient liquidity to fund its utility operations going forward. (Id.)

Ms. Phipps alleges that AmerenIP could have recalled its money pool loan to AmerenCIPS, in which case AmerenCIPS could have borrowed its funds from Ameren. (ICC Staff

Ex. 19.0 (Phipps Reb.), p. 9.) Ms. Phipps argues that if AmerenIP had recalled its money pool loan, it would not have needed to borrow $60 million from Ameren on October 21, 2008. (Id.) She further argues that if AmerenIP had not borrowed from Ameren on October 21, 2008, it could have reduced the size of its October 2008 long-term debt issue from $400 million to $350 million because it would have had less short-term debt to retire. (Id.) Ms. Phipps alleges that AmerenIP did not use the proceeds from the Ameren loan, making it dubious whether AmerenIP actually needed the Ameren loan.

Finally, Ms. Phipps argues that Ameren and its subsidiaries, including the AIUs, did not believe the potential reductions in available capacity under the credit facilities would materially affect their liquidity if Lehman Brothers Bank, FSB did not fund its commitments and that IP did not require the additional $50 million long-term debt balance to repay existing short-term indebtedness. (Id., p.11.) She argues that, because AmerenIP issued the long-term indebtedness more than one year before the AIUs' bank facilities would expire, AmerenIP did not require the $50 million to repay existing short-term indebtedness. (Id., p. 12.)

Despite the fact that Ms. Phipps agrees that when the Commission assesses the reasonableness of the actions regarding AmerenIP's capital structure, it should do so without exercising hindsight, (Tr. 259-60), these arguments utilize the benefit of hindsight and can only be made now given conditions in the capital and bank markets did not continue to worsen and in fact have improved, (Ameren Ex. 60.0 (Nickloy Sur.), p. 3.) AmerenIP would have had to continue to fund itself regardless of whether it had been able to access the capital markets in June 2009 to fund its long-term debt maturity, without having received an upgrade in its credit ratings, and regardless of the direction of commodity prices and resultant demands for collateral pricing. (Id.) Furthermore, AmerenIP was concerned about renewal one year in advance because by the time IP completed its $400 million long-term debt financing in October 2008, Moody's Investors Service (Moody's) had already been publicly signaling its focus on the renewal of IP's, and the other AIUs', bank facilities, noting this in August, and September, 2008 credit reports. (Id., pp. 3-4.) Moody's further reinforced this view in an October 2009 Special Comment "Investor-Owned Utilities Face Significant Bank Facility Refinancing Risk as Substantial 2011-2012 Maturities Approach." (Id.) At this time, bank markets were highly distressed with no sign of when or whether that market would being to improve and improve to a level such that these facilities, which are critical for maintaining availability resources, could be renewed. (Id.)

d. *Common Equity Balance – Contested*

AmerenIP's balance of common equity, $1,110,636,039, is AmerenIP's March 31, 2009 common equity balance, adjusted for purchase accounting, ratemaking and other non-cash items. (AmerenIP Ex. 13.0E Rev. (O'Bryan Dir.), p. 6.) Staff maintains that AmerenIP's balance of common equity should be $1,052,637,039 to reflect an adjustment removing the $58 million common equity infusion by Ameren during March 2009. (ICC Staff Ex. 5.0, p. 32.)

In his rebuttal testimony, Mr. Nickloy stated that he disagrees with Ms. Phipps' exclusion of the equity infusion from AmerenIP's capital structure because ignoring the credit and liquidity enhancing step of making a common equity infusion into AmerenIP implies neither of these objectives is worthwhile. (Ameren Ex. 28.0 (Nickloy Reb.), pp. 7-8.) Mr. Nickloy explained that Ameren infused $58 million of common equity into AmerenIP in an effort to bolster AmerenIP's credit quality by enhancing its credit metrics and de-levering its capital structure. (Id., p. 8.) This action was also intended to send a positive signal to the rating agencies and fixed income investors regarding the importance of AmerenIP's credit quality. (Id.) This was another of the multiple credit enhancing steps taken by Ameren and AmerenIP (including, of course, the renewal of bank facilities) which ultimately led to improvement in AmerenIP's ratings including the restoration of its issuer rating to investment grade. (Id.) This equity infusion, as well as an additional equity infusion made in September 2009 using proceeds from a recent Ameren common equity offering, further enhances AmerenIP's ability to achieve its stated equity ratio target in the range of 50% - 55%. (Id.)

As Mr. Nickloy explained, although the March equity infusion resulted in a temporary increase in cash, this enhanced AmerenIP's liquidity position and reduced the extent to which it would need to rely on its bank facilities. (Id.) At the time, AmerenIP's bank facilities had not yet been renewed and its ability to do so was uncertain. (Id.) The bank markets continued to remain challenging and AmerenIP had no assurance that it would be able to extend or replace its existing facilities and how much borrowing capacity it would have under any new facility. (Id.) The capital markets also were tentative and AmerenIP was facing a near-term $250 million long-term debt maturity. (Id.) In June, once it became apparent that AmerenIP would be able to successfully complete the renewal of its bank facilities, it elected to fund this long-term debt with cash. (Id.)

Ms. Phipps acknowledges that AmerenIP's objectives were worthwhile. (ICC Staff Ex. 19.0 (Phipps Reb.), p. 14.) However, Staff maintains that Moody's August 13, 2009 announcement of the AIUs' upgrade does not support AmerenIP's contention that the common equity infusion ultimately led to Moody's decision to restore AmerenIP's credit rating to investment grade. (Id., p. 13.) According to Ms. Phipps, Moody's expressly stated, "[t]he upgrade of Ameren's Illinois utilities is prompted by the recent execution of new bank facilities and the improved political and regulatory environment for utilities in Illinois." (Id.) Staff also argues that AmerenIP did not require an equity infusion from Ameren due to a lack of available liquidity because AmerenIP had available liquidity of at least $461 million to $590 million during March 2009. (Id.)

Mr. Nickloy acknowledges that Moody's did not specifically cite the $58 million common equity infusion in their August 13, 2009 announcement of the ratings upgrade for AmerenIP as well as that for AmerenCILCO and AmerenCIPS. (Ameren Ex. 60.0 (Nickloy Sur.), p. 4.) However, as Mr. Nickloy noted, Moody's was clearly aware of this equity infusion and plans for further equity infusions and would have incorporated that into their analysis leading to the upgrade. (Id.) Moreover, in an AmerenIP-specific credit opinion published by Moody's the day following the announcement of the upgrade, Moody's cited concerns around additional pressure on AmerenIP's financial metrics as a potential driver or factor which could drive the rating down. (Id., pp. 4-5.) Common equity infusions are helpful for financial metrics and would thus act as an offset to any factor placing negative pressure on these metrics. (Id., p. 5.)

e. *Staff's Alternative Recommendation*

In the event the Commission agrees with her adjustment to AmerenIP's long-term debt balance, but not Ms. Phipps' adjustment to AmerenIP's common equity balance, then she recommends that the Commission also not remove the $50 million in debt AmerenIP issued in October 2008 from AmerenIP's long-term debt balance. (ICC Staff Ex. 19.0 (Phipps Reb.), p. 14.) Instead, she recommends the Commission adjust the interest rate on that $50 million in debt to the embedded cost of long-term debt had the $50 million in debt not been issued, or 7.83%. (Id., pp. 14-15.) Staff maintains that, absent such an adjustment, AmerenIP's before-tax rate of return on rate base would be higher if the Commission only reduced the balance of the October 2008 debt issue than if the Commission adjusted neither the amount of the October 2008 debt issue nor the March 2009 common equity infusion. (Id., p. 15.)

C. Cost of Preferred Stock – Resolved for CILCO, CIPS and IP

Mr. O'Bryan testified that AmerenCIPS' embedded cost of preferred stock was 5.129% as of December 31, 2008, (AmerenCIPS Ex. 13.0E Rev. (O'Bryan Dir.), p. 7), that AmerenIP's embedded cost of preferred stock was 5.010% as of March 31, 2009, (AmerenIP Ex. 13.0E Rev. (O'Bryan Dir.), p. 8), and that AmerenCILCO's embedded cost of preferred stock was 4.613% as of March 31, 2009, (AmerenCILCO Ex. 13.0G (O'Bryan Dir.), p. 7.) Mr. O'Bryan included expenses associated with the issuance of perpetual preferred stock, including discount and premium, plus any loss incurred in acquiring/redeeming prior series, in each of the embedded cost calculations. (AmerenCIPS Ex. 13.0E Rev. (O'Bryan Dir.), p. 7; AmerenIP Ex. 13.0E Rev. (O'Bryan Dir.), p. 8; AmerenCILCO Ex. 13.0G (O'Bryan Dir.), p. 8; AmerenCIPS Ex. 13.4.) Staff agrees with the AIUs' proposals. (ICC Staff Ex. 5.0 (Phipps Dir.), pp. 18, 23, 31-32.)

D. Cost of Long-Term Debt

1. CILCO – Contested

Mr. O'Bryan testified that AmerenCILCO's embedded cost of long-term debt was 8.161% as of March 31, 2009. (AmerenCILCO Ex. 13.0G (O'Bryan Dir.), p. 6.) However, Staff seeks to adjust the coupon rate for AmerenCILCO's 8.875% bonds to reflect AmerenCILCO's alleged higher business risk profile due to its non-utility affiliates. (ICC Staff Ex. 5.0 (Phipps Dir.), pp. 15-

16.) Staff maintains that, during December 2008, AmerenCILCO's issuer rating from Moody's was Ba1 and its senior secured debt rating was Baa2. (Id., p. 16.) Staff acknowledges that Moody's classifies AmerenCILCO as having a "Medium" business risk, however, Staff maintains Moody's views U.S. transmission and distribution utilities' business risk as "Low." (Id.) Ms. Phipps evaluated Moody's rating factors for AmerenCILCO using the benchmarks for low business risk electric utilities, and concluded that AmerenCILCO's implied issuer rating would be Baa1 for its regulated utility operations. (Id.) Ms. Phipps argues that, since AmerenCILCO's secured debt rating is two notches above its unsecured ratings, Moody's would assign AmerenCILCO a secured debt rating of A2 if non-utility affiliates had not increased its business risk. (Id.) Ms. Phipps makes a similar argument with respect to the S&P rating, arguing that since AmerenCILCO's current S&P secured debt rating is two notches above its issuer rating, S&P would assign AmerenCILCO a secured debt rating of A if its business risk profile was affected by its riskier non-utility affiliates. (Id., p. 17.)

Ms. Phipps also changed various dates to conform to AmerenCILCO's 2008 Form 21 annual report and set the annual amortization of expense, premium, or discount, and loss or gain for each debt issue using a rate that she purports recovers those debt costs in equal monthly amounts between the embedded cost of debt measurement date and the end of the applicable amortization period. (Id., p. 18.) Ms. Phipps also argues for removal of three months of amortization from the year-end 2008 unamortized balances of expense, premium or discount, and loss or gain for each debt issue to determine the unamortized balances on the March 31, 2009 measurement date. (Id.)

However, as noted above, the rating agencies use a combination of qualitative factors along with quantitative analysis in determining an issuer's credit ratings, and are ultimately the final arbiters of credit ratings. (Ameren Ex. 28.0 (Nickloy Reb.), p. 4.) Any adjustment based on an assumption that CILCO would be entitled to a higher rating is unfounded. (Id.) Furthermore, Ms. Phipps does not offer any compelling evidence that AmerenCILCO's rating, or the coupon/interest rate on AmerenCILCO's 2008 long-term debt issuance would have been any different than what either was at the time this debt was issued. (Id.) AmerenCILCO needed to complete this refinancing in order to reduce borrowings under its bank facilities (its borrowing sublimits thereunder were fully utilized at the time) and improve its liquidity position. (Id., pp. 4-5.) This was a prudent, yet difficult, refinancing action, and to deprive the company of its ability to adequately recover the cost of this capital in effect is penalizing AmerenCILCO for taking a prudent action to protect its ability to maintain appropriate levels of liquidity and ensure a reliable, continuing ability to make payments, including the posting of collateral, to its suppliers, employees, etc. on a contractual and timely basis going forward. (Id., p. 5.)

Ms. Phipps maintains that she does not address whether AmerenCILCO should have issued the long-term debt. (ICC Staff Ex. 19.0 (Phipps Reb.), p. 3.) She continues to argue that AmerenCILCO is affected by its non-utility affiliates. (Id.) However, as discussed above, Ms. Phipps cannot step into the shoes of the ratings agencies and reasonably opine that the credit ratings for AmerenCILCO would be any different than they are today if it no longer had an unregulated generation subsidiary and/or was no longer owned by an intermediate parent company. (Ameren Ex. 60.0 (Nickloy Sur.), p. 2.)

2. CIPS – Resolved

AmerenCIPS initially proposed 6.760% as its embedded cost of long-term debt as of December 31, 2008. (AmerenCIPS Ex. 13.0E Rev. (O'Bryan Dir.), p. 6; AmerenCIPS Ex. 13.2.) Staff proposed an adjustment to remove from AmerenCIPS's embedded cost of long-term debt any incremental cost increase due to its decision to refinance a $67 million, five-year intercompany promissory note bearing 4.7% with $61.5 million in 30-year bonds bearing a 6.7% interest rate, resulting in a 6.491% embedded cost of long-term debt. (ICC Staff. Ex. 5.0 (Phipps Dir.), p. 21, Sch. 5.01.) Ms. Phipps also changed various dates in the cost of long-term debt schedule to conform to AmerenCIPS's 2008 Form 21 annual report and set the annual amortization of expense, premium or discount, and loss or gain for each debt issue using a rate that recovers those debt costs in equal monthly amounts between the embedded cost of debt measurement date and the end of the applicable amortization period. (Id., pp. 22-23.)

While Mr. O'Bryan did not agree with Staffs' removal of the incremental cost due to its decision to refinance the 4.70% intercompany note with 6.7% from CIPS' embedded cost of long-term debt, Mr. O'Bryan accepted Ms. Phipps' position on this issue for the purposes of this case only. (Ameren Ex. 37.0 Rev. (O'Bryan Reb.), p. 3.)

3. IP – Contested

Mr. O'Bryan testified that IP's embedded cost of long-term debt was 8.088% as of March 31, 2009. (AmerenIP Ex. 13.0E Rev. (O'Bryan Dir.), p. 6.) IP issued $400 million of long-term debt in October 2008. (Ameren Ex. 28.0 (Nickloy Reb.), p. 5.) For the purposes of her testimony, Ms. Phipps adjusted the principal amount of this issuance to $350 million. (Id.) Based on this reduction, Ms. Phipps reduced the total debt expense and debt discount based on the lower principal amount. (ICC Staff Ex. 5.0 (Phipps Dir.), p. 30.) However, Mr. Nickloy argues

Ms. Phipps' exclusion of a portion of the principal amount of AmerenIP's long-term debt issuance is improper. (See Ameren Ex. 28.0 (Nickloy Reb.) p. 5.) Thus, Ms. Phipps' adjustments to IP's long-term cost of debt are equally misplaced.

E. Cost of Short-Term Debt including Bank Commitment Fees

As a general matter, while the AIUs accepted Staff's proposal that bank facility costs should be recovered by a direct adder to each AIUs' cost of capital, as explained by AIU witness O'Bryan, Ms. Phipps makes errors in her allocation of the fees, and thus understates the overall cost of capital. (Ameren Ex. 37.0 Rev. (O'Bryan Reb.), p. 4.)

First, Ms. Phipps erroneously assigns a lower amount of total upfront fees according to her calculations contained in her direct testimony work papers than the amount actually realized by the AIUs in connection with putting the Illinois Facility in place. (Id.) Her calculations incorrectly utilize a 1.50% - 1.75% upfront fee rate range rather than the correct 1.50% - 2.00% upfront fee range incurred. (Id.) Apparently she does this assuming that the various facility commitment levels, or tiers, and their corresponding upfront fee rates are based on certain total size of all commitments, and reduces those tiers based on the smaller size of the Illinois facility ($800mm) relative to the total size of the Ameren facilities being arranged at the time ($2.15B). (Id.) Ms. Phipps' calculations incorrectly assume that the upfront fee tiers (i.e. the 1.50% - 2.00% range) would be lower if the total facility size is lower. (Id.) It would be wrong to suggest that banks would be willing to lend into a smaller (Illinois only) facility at a 1.50% rate. (Id.) In fact, smaller bank facilities recently completed by Integrys Energy Group ($500 million) and another electric utility ($265 million) suggest otherwise. (Id.) Upfront fees in those bank facilities were 2.00% for all borrowers in the Integrys' case and 3.00% for all borrowers in the other electric utility's case. (Id., pp. 4-5.) If Ameren had only been arranging the $800 million Illinois Facility and not a total of $2.1 billion of multiple credit facilities it would have still paid upfront fee rates in the 1.50% - 2.00% range; it would have simply required participation from fewer lenders and/or smaller commitments from these lenders with a corresponding reduction in various commitment level tiers in dollar terms. (Id., p. 5.)

Second, Ms. Phipps allocates the bank fees incorrectly to the various parties of the Illinois Facility. (Id.) She subtracts Ameren's entire sublimit, along with an equal proportion of the costs, under the facility from the total facility size rather than the total sublimits of the participants. (Id.) She argues that Mr. O'Bryan's methodology of allocating the facility fees does not recognize that Ameren's sublimit could reduce the AIUs' borrowing capacity to $500 million from $635 million. (Id.) To the contrary, her approach would assign too much cost to Ameren, and too little to the AIUs.

Accordingly, the parties to this facility and their individual borrowing sublimits are as follows:

AmerenCIPS	$135 million
AmerenCILCO	$150 million
AmerenIP	$350 million
Ameren Corp.	$300 million
Total Sublimits	**$935 million**

(Id.) The sublimits total of $935 million obviously exceeds the size of the credit facility ($800 million). (Id.) This is not unusual, as it is predicated on the assumption that borrowers' needs fluctuate and coincident borrowing at the maximum amount of each sublimit is rare. (Id., pp. 5-

6.) Sublimits, therefore, reflect the absolute maximum amount of debt that the borrower can have at any point in time and are largely based on potential peak borrowing needs rather than consistent, ongoing borrowing levels. (Id., p. 6 (emphasis in original).)

While it is true that Ameren could at any time borrow up to its sublimit of $300 million and reduce the amount available to the AIUs under the facility to $500 million from $635 million, Ms. Phipps' methodology, however, wrongly assumes that Ameren will consistently do so over the life of the facility and ignores the fact that Ameren Corp. may borrow under the facility in order to provide funds to the AIUs. (Id.)

The sublimits in the case of the AIUs also reflect their mortgage bond capacities since the security of the mortgage bonds was a necessity to the participating lenders. Since mortgage bonds are limited and in many cases, a precious resource, the sublimits in these instances are somewhat lower than would be absent the security. (Id.)

Ms. Phipps also ignores the fact that Ameren can and does from time to time provide supplemental liquidity to the AIUs and can act as their "lender of last resort" when their individual borrowing sublimits are at their maximum and there is no additional liquidity available in the utility money pool. (Id.) For example, this was the case between October 27, 2008 and October 29, 2008 when Ameren lent between $4.1 million and $13.6 million into the utility money pool at a time when AmerenCILCO's credit facilities sublimit total of $150 million was at capacity and the other AIUs did not have any additional funds to lend. (Id.)

Lastly, third quarter borrowing (representing the initial quarter that the Illinois Facility was in place) from this facility shows that Ameren's average daily amount outstanding was

$133.3 million, far less than the $300 million assumed by Ms. Phipps in her analysis. (Id., pp. 6-7.)

The objective of allocating the costs of the facility is to do so fairly so as to not overcharge or undercharge the AIUs fair share of the fees. (Id., p. 7.) Mr. O'Bryan achieves this result by allocating the total bank facility fees by each borrower's proportion of the total borrower sublimits under the facility. (Id.) The effect is to set the AIUs collective allocation of the total Illinois Facility fees at 67.9%, rather than at 62.5% as Ms. Phipps does:

AmerenCIPS	$135 million	14.44%
AmerenCILCO	$150 million	16.04%
AmerenIP	$350 million	37.43%
Ameren Corp.	$300 million	32.09%
Total Sublimits	**$935 million**	**100.00%**

(Id.)

This method of allocation is fair in that it does not show bias toward any borrower beyond what its individual sublimit implies. (Id.) Just as the AIUs should not be on the hook for subsidizing Ameren's costs of accessing credit, Ameren should not subsidize the costs of the AIUs. (Id.) Under Ms. Phipps' approach, the AIUs could borrow over 79% of the available facility (not counting any borrowings by Ameren on their behalf), but bear just 62.5% of the cost. (Id.) Weighting cost responsibly in proportion to sublimits is far more reasonable. (Id.)

In her rebuttal testimony, Ms. Phipps attempts to discredit Mr. O'Bryan's arguments refuting her lowering of the banks' commitment fees; however, her arguments are not compelling and in some ways actually damage her own position. (Ameren Ex. 59.0 (O'Bryan

Sur.), p. 2.) Ms. Phipps claims that the two examples supporting Mr. O'Bryan's argument that smaller facilities and bank commitments can have higher commitment fee rates have no value. (Id.) Her arguments include differing closing dates between Mr. O'Bryan's examples and the Illinois Facility and, in the Integrys Energy Group case, replacing a relatively small portion of the company's aggregate bank facilities. (Id.)

First, her argument regarding the Integrys case is puzzling since Mr. O'Bryan's argument centered on the fact that there is no reason that the Illinois Facility should have a lower upfront fee that the larger aggregate ($1.5 million facility the $150 million supplemental facility together with the Illinois Facility) Ameren facilities. (Id.) In fact, her argument actually supports Mr. O'Bryan's position. (Id.) Even though the Integrys example is a small facility and represents a fairly minor portion of Integrys' aggregate bank facilities, it attracted higher upfront fee rates. (Id.)

Second, Ms. Phipps points out that the two examples Mr. O'Bryan cited in his rebuttal offer proof that each bank deal is different with its own unique circumstances. (Id.) These unique circumstances include, but are not limited to, absolute size of the facility, size of the facility relative to the borrower's total facilities, borrower's credit ratings, date the facility is put in place, opportunity for ancillary business and terms of the facility (tenor, existence of an extension option, security, etc.). (Id., pp. 2-3.) This offers support for Mr. O'Bryan's argument that Ms. Phipps' lowering of the upfront fee rate to the lowest rate tranche for the aggregate Ameren facilities is improper. (Id., p. 3.) Each deal presents a unique set of circumstances and involves a negotiation process with a unique group of financial institutions. (Id.) The correct adjustment is to maintain the same upfront fee rate that the banks agreed to pursue to the actual negotiations involving the Ameren facilities and applying it to the lower AIUs' commitment. (Id.)

Nor are Ms. Phipps' arguments regarding allocation of bank upfront and facility fees compelling. (Id.) Ms. Phipps' position assumes Ameren's borrowing in this facility will crowd out the AIUs thus not allowing the AIUs full sublimit access. (Id.) History shows such a case is very unlikely. (Id.; Tr. 231.) First, on any day that Ameren may in fact borrow up to its full sublimit of $300 million, and one of the three AIUs would also be borrowing up to their full sublimit, each of the remaining two AIUs would have their full sublimit available to borrow from assuming the other is not borrowing from the facility. (Ameren Ex. 59.0 (O'Bryan Sur.), pp. 3-4.) It should be noted that over the past two years (371 total days) there have been only two days (.3% of the time) that more than one of the AIUs have borrowed at their sublimit on the same day. (Id., p. 4.) Over the same time period aggregate AIUs borrowing has exceeded $500 million on just 53 days (7.25% of the time). This exact situation (i.e. aggregate AIUs borrowing exceeding $500 million) would have to be combined with Ameren borrowing on the same day at a greater than twice the rate of its current average daily borrowing since the facility has been in existence to effect the borrowing capacity of the AIUs. (Id.) As previously mentioned, borrowers needs fluctuate and coincident borrowing at the maximum amount of each sublimit is rare (Id.) Additionally, Ameren has access to $1.3 billion of credit facilities outside of the Illinois Facility at a rate that is slightly lower than the rate that it can borrow from the Illinois Facility. (Id.) Therefore it has a financial incentive to borrow from the other facilities. (Id.) Consequently, Ameren has thus far shown that it is not borrowing as heavily from the Illinois Facility as the other facilities since the facilities were put in place on June 30, 2009. (Id.)

Ameren's average daily borrowing from the Illinois Facility is $81 million while over the same period it was borrowing at an average rate of $302 million per day from the other facilities. (Id.) There is, therefore, no other proper and fair means to allocate the credit facility fees than by the proportion of sublimits Mr. O'Bryan laid out in his rebuttal testimony. (Id.)

1. CILCO – Contested

AmerenCILCO maintains that its cost of short-term debt is 2.150%. (Ameren Ex. 37.1, p. 1.) Since AmerenCILCO does not have any short-term debt currently outstanding, the cost of short-term debt was calculated in accordance with the terms of the source of AmerenCILCO's last short-term borrowing—its credit facilities. (AmerenCILCO Ex. 13.0G (O'Bryan Dir.), p. 6.) The cost is the sum of the April 30, 2009 one-month LIBOR and the applicable margin, which is based on both AmerenCILCO's current senior secured credit ratings (Baa2/BBB+) and the current utilization of the facility at the time of the loan. (Id.) The utilization of the facility is the total percentage of the facility drawn by all borrowers of the facility. (Id.) If the facility is under 50% drawn, AmerenCILCO's spread over LIBOR would be 0.600% and if the facility is over 50% drawn, the spread over LIBOR would be 0.850%. (Id.) The spread over one-month LIBOR was calculated by taking an average of the utilization spreads. (Id., p. 7.) Mr. O'Bryan argued that the costs associated with the AmerenCILCO's credit facilities should be included in AmerenCILCO's A&G expenses because such fees are fixed expenses paid on the entire credit facility and do not change nor have any relationship to the amount of funds borrowed from the facility. (Id.)

Staff initially estimated AmerenCILCO's cost of short-term debt to be 2.15%, (ICC Staff Ex. 5.0 (Phipps Dir.), p. 13), however, Ms. Phipps subsequently adjusted this rate to 2.50%

based on Moody's August 2009 revised credit rating methodology, (ICC Staff Ex. 19.0 (Phipps Reb.), p. 7). Ms. Phipps argues that that the new methodology does not provide distinguishable business risk categories that permit evaluating financial metric for a "Medium" risk utility that owns generation versus a "Low" risk distribution utility. (Id.) On this basis, Ms. Phipps relied upon AmerenCILCO's actual senior secured debt rating from Moody's (Baa1) and her estimate of AmerenCILCO's S&P rating, adjusted solely to reflect a lower degree of business risk (A). (Id.) Ms. Phipps argues that, pursuant to the Illinois credit facility, AmerenCILCO's implied Baa1/A ratings would result in a Level II borrower status. (Id.) Thus, she maintains this would result in a 2.50% cost of short-term debt for AmerenCILCO, which equals the weighted average of AmerenCILCO's bank loan rate (i.e., the August 18, 2009, LIBOR rate, plus a 2.375% margin for Level II status) and the internal money pool rate (0.19%). (Id.) Finally, Ms. Phipps argues for the addition of 28 basis points to AmerenCILCO's overall cost of capital to reflect bank commitment fees, including a Level II borrower facility fee of 0.375%. (Id., Sch. 19.05.)

First, Ms. Phipps makes no such argument for AmerenCIPS and AmerenIP. (Ameren Ex. 28 (Nickloy Reb.), p. 2.) AmerenCILCO's current senior secured ratings are Baa1/BBB+ which are the same as AmerenCIPS and AmerenIP in the case of Moody's, and in the case of S&P, the same as AmerenCIPS and one notch better than AmerenIP. (Id.) Ms. Phipps' proposed ratings for AmerenCILCO are two notches higher than its current ratings and are at least two notches higher than the current ratings for its two Illinois utility facilities. (Id.) Neither AmerenCIPS nor AmerenIP has an unregulated generation subsidiary. (Id.)

Ms. Phipps undertakes a ratings analysis in an attempt to remove the effect of AmerenCILCO's affiliates and determine, in her view, the resulting AmerenCILCO ratings. (Id.)

First, Mr. Nickloy notes that under Moody's recently updated ratings methodology approach, AmerenCILCO scores the same for the various qualitative factors as does CIPS and IP. (Id.) Second, Ms. Phipps analyzes AmerenCILCO's ratings on the basis of an S&P matrix. (Id., p. 3.) S&P uses this matrix as a guideline tool and stated in their May 2009 publication that "it is essential to realize that the financial benchmarks are guidelines, neither gospel nor guarantees." (Id.) Given this variability in matrix-indicated outcomes versus an actual ratings outcome, as S&P takes pains to point out, Ms. Phipps' argument that AmerenCILCO should have a "Strong" business risk profile and thus an issuer rating of BBB+ (at a "Significant" financial risk profile) represents an outcome one notch above the matrix indicated rating and thus be BBB-. (Id., p. 4.) This is the same as the current issuer rating. (Id.)

It cannot be overstated that the rating agencies are the final arbiters of credit ratings. (Id.) The rating agencies use a combination of qualitative factors along with quantitative analysis including an assessment of key financial measures in determining an issuer's credit ratings. (Id.) There is nothing automatic about any particular ratings outcome, contrary to what Ms. Phipps implies, and any adjustment based on an assumption that AmerenCILCO would be entitled to a higher rating is unfounded. (Id.)

Simply stated, Ms. Phipps cannot step into the shoes of the ratings agencies and reasonably opine that the credit ratings for AmerenCILCO would be any different than they are today if it no longer had an unregulated generation subsidiary and/or was no longer owned by an intermediate parent company. (Ameren Ex. 60.0 (Nickloy Sur.), p. 2.) Given the level of judgment exercised by the rating agencies, and the inclusion of both qualitative and quantitative elements in their analyses, Ms. Phipps is not in a position to compellingly argue a certain ratings outcome. (Id.) With respect to her analysis of AmerenCILCO's rating using S&P analytical matrix tool, Ms. Phipps states, "that S&P decided to disclose what CILCO's business profile would be in the absence of AERG and CILCORP's indebtedness indicates that information is sufficient to affect CILCO's credit ratings." (Id.) This is clearly speculation on her part. (Id.) Furthermore, in referencing Moody's August 14, 2009 report, she does not acknowledge that Moody's cannot publicly disclose in their reports non-public information provided to them by rated issuers. (Id.) She points to Moody's provision of historical financial metrics in that report, when of course they cannot provide confidential forward-looking projected metrics derived from projected financial statements provided to them by the issuer in those reports. (Id.) However, these projections of future financial performance are a critical part of their ratings analysis. (Id.)

For the same reasons provided above, Ms. Phipps' adjustment to AmerenCILCO's bank facility fee is unwarranted. (Ameren Ex. 28 (Nickloy Reb.), p. 3.)

2. CIPS – Resolved

AmerenCIPS initially proposed that its cost of short-term debt was 0.180%, its prevailing cost as of April 30, 2009. (AmerenCIPS Ex. 13.0E Rev. (O'Bryan Dir.), p. 6.) According to AmerenCIPS, as of April 30, its short-debt consisted entirely of money pool borrowings and the overall cost of these borrowed funds was calculated in accordance with the Ameren Utility Money Pool Agreement procedures. (Id.) AmerenCIPS also argued that both upfront and facility fees associated with its credit facilities should be included in AmerenCIPS's A&G expenses because such fees are fixed expenses paid on the entire credit facility and do not change nor have any relationship to the amount of funds borrowed from the facility. (Id., p. 7.)

Staff witness Ms. Phipps estimated AmerenCIPS's cost of short-term debt to be 1.50%. (ICC Staff Ex. 5.0 (Phipps Dir.), p. 19.) Ms. Phipps also recommended adding 15 basis points to AmerenCIPS's overall cost of capital to reflect bank commitment fees. (Id.) Ms. Phipps calculated AmerenCIPS's weighted cost of short-term debt based on the proportion of AmerenCIPS's borrowings at a bank loan rate of 3.02% and an internal money pool rate of 0.19%. (Id., pp. 19-20.) In her direct testimony, Ms. Phipps stated that during the short-term debt period, 46% of the Company's short-term borrowings were at the bank loan rate and 54% were at the internal money pool rate. (Id., p. 20.) Thus, Ms. Phipps maintains the weighted average interest rate for AmerenCIPS's short-term debt equals 1.50%. (Id.)

While Mr. O'Bryan disagreed with Ms. Phipps reasoning for not including upfront facility fees in A&G expenses, Mr. O'Bryan accepted her general methodology for the calculation of the costs and the addition of these costs as a direct adder to AmerenCIPS's of capital. (Ameren Ex. 37.0 Rev. (O'Bryan Reb.), p. 3.) AmerenCIPS does not contest Staff's adjustments, as Mr. O'Bryan's updated weighted average cost of capital schedule in Ameren Exhibit 37.1 reflects a 1.50% weighted cost of short-debt for AmerenCIPS. (Ameren Ex. 37.1.)

3. IP – Resolved

AmerenIP initially proposed that its short-term cost of debt was 1.361%. (AmerenIP Ex. 13.0E Rev. (O'Bryan Dir.), p. 6.) AmerenIP argued that the fees associated with the credit facilities should be included in AmerenIP's A&G expenses because such fees are fixed expenses paid on the entire credit facility and do not change nor have any relationship to the amount of funds borrowed from the facility. (Id., pp. 7-8.) Staff argued that AmerenIP's cost of short-term debt equals AmerenIP's 3.02% bank loan rate. (ICC Staff Ex. 5.0 (Phipps Dir.), p. 24.) Ms. Phipps also recommended adding 16 basis points to AmerenIP's overall cost of capital to reflect bank commitment fees. While Mr. O'Bryan disagreed with Ms. Phipps' reasoning for not including upfront facility fees in A&G expenses, Mr. O'Bryan accepted Ms. Phipps' general methodology for the calculation of the costs and the addition of these costs as a direct adder to AmerenIP's cost of capital. (Ameren Ex. 37.0 Rev. (O'Bryan Reb.), p. 3.) AmerenIP does not contest Staff's adjustments, as Mr. O'Bryan's updated weighted average cost of capital schedule in Ameren Exhibit 37.1 reflects a 3.02% weighted cost of short-debt for AmerenIP. (Ameren Ex. 37.1.)

F. Cost of Common Equity

1. Resolved Issues

2. Contested Issues

a. *Return on Equity Estimates*

Ms. McShane makes the following recommendations for AIUs' costs of equity: For the gas distributors of AmerenCILCO, AmerenCIPS, and AmerenIP, the cost of common equity is 11.2%, 10.8%, and 11.2%, respectively. For the electric utilities, the cost of common equity is 11.7%, 11.3%, and 11.7%, respectively.[27] (Ameren Ex. 52.0 (McShane Sur. Reb.), p. 2.)

The other parties – Staff (through Staff witness Ms. Freetly), Illinois Industrial Energy Consumers (through IIEC witness Mr. Gorman), and Citizens Utility Board (through CUB witness Mr. Thomas) – recommend the following costs of equity:

- Ms. Freetly calculates costs of equity for the gas operations as 9.64% for AmerenCILCO, 9.38% for AmerenCIPS, and 9.64% for AmerenIP. (ICC Staff Ex. 20.0 (Freetly Reb.), p. 1.) For electric delivery service operations, Ms. Freetly

[27] These recommendations are based on current economic circumstances, which are improved somewhat from the previous financial crisis and in which it is easier for the AIUs to attract capital than it was when Ms. McShane wrote her direct testimony. (Tr. 514.)

recommends costs of common equity of 10.38% for AmerenCILCO, 10.14% for AmerenCIPS, and 10.44% for AmerenIP. (Id., p. 2.)

- Mr. Gorman proposes a combined return on equity of 10.0% for AIUs that reflects AIUs' actual combination gas and electric investment fundamentals. (IIEC Ex. 6.0-C (Gorman Reb.), pp. 2-3.)
- Mr. Thomas calculates that the cost of common equity for AIUs' electric operations is 8.76% and the cost of common equity for AIUs' gas operations is 7.97%. (CUB Ex. 2.0 (Thomas Reb.), p. 2.)

Use of Samples

Each party bases its analysis on a sample group for the respective service because the AIUs' operations should reflect the risk profile and cost of equity of comparable utilities. (See, e.g., AmerenCIPS Ex. 12G (McShane Dir.), p. 2.) For the AIUs' gas operations, Ms. McShane selected a sample of nine comparable gas distribution utilities ("LDCs") according to certain criteria specified in her testimony. (Id., p. 8.) For the AIUs' electric operations, Ms. McShane selected a sample of 29 electric utilities according to similar criteria specified in her testimony. (AmerenCIPS Ex. 12E (McShane Dir.), p. 9.) Ms. Freetly uses the same gas sample as Ms. McShane and a subset of her electric sample. (ICC Staff Ex. 6.0 (Freetly Dir.), pp. 3-4.) Mr. Gorman and Mr. Thomas both rely on the same electric and gas proxy groups as Ms. McShane. (IIEC Ex. 2.0 (Gorman Dir.), p. 18; CUB Ex. 1.0 (Thomas Dir.), p. 15.)

b. *DCF and CAPM Model Issues*

(1) Comparable Earnings Test

Ms. Freetly and Mr. Gorman criticize the use of the comparable earnings test for determining the cost of equity. (ICC Staff Ex. 6.0 (Freetly Dir.), p. 48; IIEC Ex. 6.0-C (Gorman Dir.), p. 79.) Similarly, Mr. Thomas asserts that the Commission has rejected the comparable earnings method in the past. (CUB Ex. 1.0 (Thomas Dir.), pp. 44-45.) This criticism misinterprets Ms. McShane's use of the comparable earnings test in her cost of equity analysis. In fact, Ms. McShane agrees that the comparable earnings test does not measure the investor's opportunity cost of attracting equity capital as measured relative to market values. (Ameren Ex. 12.0E (McShane Dir.), pp. 69-70.) Thus, she does not use the comparable earnings test to actually determine the cost of equity. (Ameren Ex. 36.0 (McShane Reb.), p. 49.) Rather, the comparable earnings test provides a measure of the fair return based on the concept of opportunity cost, and the returns earned by relatively low risk unregulated companies provide a relevant perspective on the reasonableness of the recommended return on equity. (Id., p. 50.) The results of Ms. McShane's comparable earnings test here indicate the Companies' proposed returns on equity for the AIUs, as calculated by the DCF and equity risk premium tests, are conservative when compared to the earnings level of relatively low risk unregulated companies. (Id., pp. 49-50.)

c. *Growth Rates*

Ms. McShane relies on three Discounted Cash Flow ("DCF") estimates: (1) a constant growth model that relies on analysts' earnings forecasts; (2) a sustainable growth model; and (3) a multi-stage model that includes both analysts' forecasts and nominal GDP growth as proxies for longer-term growth. (Ameren Ex. 36.0 (McShane Reb.), p. 43.) Because she weighs all three estimates, she incorporates a potential range of utility investor expected returns. (Id.)

Ms. Freetly applies a multi-stage non-constant-growth quarterly DCF model to both her gas and electric samples.[28] (ICC Staff Ex. 6.0 (Freetly Dir.), pp. 4-5.) Her DCF analysis uses three stages of dividend growth: (1) a near-term growth stage (assumed to last five years); (2) a transitional growth stage, from the end of the fifth year to the end of the tenth year; and (3) a "steady-state" growth stage assumed to begin after the tenth year.[29] (Id., pp. 6-7.)

Ms. Freetly's use of a multi-stage non-constant-growth quarterly DCF model is a departure from Staff's typical model – a constant growth (single stage) DCF model. (ICC Staff Ex. 6.0 (Freetly Dir.), p. 5.) Staff has not typically used a non-constant growth DCF model because it is more elaborate and has additional unobservable growth rate variables. (Id.) These growth rate variables are likely subject to greater measurement error than the analyst growth rate estimates in constant-growth DCF analyses. (Id.) However, Ms. Freetly argues that the levels of growth indicated by the average 3-5 year growth rates for her samples here are not sustainable over the long-term – largely because the analysts' growth forecasts (average Zacks growth rates) for the samples are higher than the current growth expectations for the economy. (Id., p. 6.) Therefore, she uses a multi-stage, non-constant growth DCF model. (Id.)

[28] Ms. Freetly denies that her use of a constant growth DCF to estimate the return on the market rather than the non-constant growth DCF applied to the samples indicates anything about the utility of the constant growth DCF analysis on the samples. Rather, she explains that she uses the constant growth DCF to estimate the return on the market because of the extreme difficulty of applying the more elaborate non-constant growth DCF on 500 companies. (ICC Ex. 20.0 (Freetly Reb.), p. 26.)

[29] Ms. Freetly uses an estimate of the long-term overall economic growth rate as the steady-stage growth for her gas and electric samples. (ICC Ex. 6.0 (Freetly Dir.), pp. 8-9.) However, she acknowledges that the overall economic growth rate may be biased upward for generally low-growth companies like utilities, but she still uses the overall economic growth rate because "it is much closer to the growth rate that investors could reasonably expect utilities to sustain over the long-term." (Id., pp. 9.)

Ms. Freetly's departure is not warranted in this case. Contrary to Ms. Freetly's reservations, analysts' forecasts are the most objective measure of investor expectations that are embedded in the stock prices and dividend yields used to estimate the DCF cost of equity. (Ameren Ex. 52.0 (McShane Sur.), p. 7.) Plus, as she admits, Ms. Freetly has previously relied on a constant growth DCF model when analysts' consensus forecasts were higher than the forecast long-term growth in the economy. (Ameren Ex. 36.0, p. 6.) Additionally, Ms. Freetly uses a constant growth DCF test to develop her equity risk premium model. (Id., p. 7.) If a constant growth DCF model is appropriate for the equity risk premium model, it is also appropriate for developing an expected return. (Id.)

Ms. Freetly's use of the average of the constant growth and the three-stage DCF models, rather than the results of the three-stage model alone, recognizes the imprecision of the period during which investors might expect analysts' forecast growth rates to persist and avoid potentially internally inconsistent results. (Ameren Ex. 52.0, p. 8.) The multi-stage model can also create inconsistencies in the DCF cost estimates for the individual companies, possibly causing a discrepancy between the multi-stage DCF costs of equity and the respective sample averages. (Ameren Ex. 52.0, p. 7-8.) It is more reasonable to give equal weight to the results of both the constant growth and multi-stage models. (Id.)

Ms. Freetly's application of her multi-stage analysis is further flawed due to the variables she uses in her model.

<u>Forward yields v. Direct forecast</u>

In the final stage of her multi-stage DCF analysis, Ms. Freetly uses forward yields on the 20-year Treasury bonds as a proxy for long-term GDP growth. According to Ms. Freetly, the changes in the Treasury yield indicate that investors' current long-term expectations vary over time. (ICC Staff Ex. 20.0 (Freetly Reb.), p. 27.) She argues the yield on Treasury bonds is a timely gauge of expected long-term economic growth because it reflects changing investor expectations due to current economic conditions. (Id.) She also posits that long-term forecasts, from which Ms. McShane implies that investor expectations of long-term growth are essentially static, might not be often updated. (Id.)

While Ms. Freetly is correct that the Blue Chip long-term consensus forecast of GDP growth extends only ten years, and that some long-term GDP forecasts are updated only annually or infrequently, her arguments do not support the use of forward interest rates as a proxy for long-term GDP growth. (Ameren Ex. 52.0 (McShane Sur.), p. 9.) First, there is no basis to conclude that investors will not rely on forecasts of GDP over the next ten years as the best available estimate for very long term growth. (Id.) Moreover, the stability of the Blue Chip 10-year consensus forecasts of GDP growth likely represents the expected reversion of growth to trend levels. (Id.) Therefore, compared to forward yields, it is more appropriate to use a direct estimate of long-term economic growth as provided by the consensus of economists' forecasts. (Ameren Ex. 36.0 (McShane Reb.), p. 5.) Such an estimate reduces the possibility of potential bias because it represents the mean of a large sample of economic forecasts. (Id.)

The proposition – that the long-term risk-free rate of interest and GDP growth should eventually be similar – is correct in theory, but there are too many influences to conclude that the forward 20-year Treasury yield is a good proxy for investor expectations of long-term growth of the economy. (Ameren Ex. 52.0, p. 10.) Such factors put downward pressure on U.S. Treasury bond yields and include influences on interest rates, high global demand for U.S.

securities, and the global savings glut. (Id.) Although the difference between the specific implied forward yield on the 20-year Treasury and the most recent consensus forecast of long-term economic growth is relatively small, the capital market experience over the past two years shows the differential can be substantial. (Ameren Ex. 36.0, p. 5.)

Spot interest rates v. forecast interest rates

Ms. McShane applies an average daily stock price over a relatively short period of time when applying the DCF test.[30] (Ameren Ex. 36.0 (McShane Reb.), p. 41.) Ms. Freetly criticizes this use of historic data and advocates a "spot" stock price. (ICC Staff Ex. 20.0 (Freetly Reb.), p. 34.) However, the price of a stock can rise or fall temporarily on any given day. (Ameren Ex. 36.0, pp. 40-41.) A "spot" stock price therefore may be quickly reversed. (Id., p. 41.) In addition, "spot" stock prices are typically combined with a corresponding growth rate forecast, which may have been prepared and disseminated earlier, and which may lead to a mismatch between the price and investor growth expectations – and thus, an erroneous DCF cost. (Id.) Therefore, the preferable price for the DCF test is an average daily price over a relatively short period of time, as Ms. McShane utilizes. (Id.)

Gorman's Growth Rate Arguments

Mr. Gorman employs three DCF models – a multi-stage model, a sustainable growth model, and a constant growth model. (IECC Ex. 6.0-C (Gorman Reb.), p. 4.) To compute return on equity, Mr. Gorman gives his DCF and CAPM tests equal weight. (Id., p. 12.) Because, as he argues, the AIUs are a combination utility – a combined risk reflected in its bond rating, its

[30] Ms. McShane used the average of daily closing stock prices for the period February 26, 2009 to March 26, 2009. (AmerenCILCO Exhibits 12.0E.4, 12.0E.5, and 12.0E.6; AmerenCILCO Exhibits 12.0G.4, 12.0G.5, 12.0G.6.)

operating risk, and the operating risk considered by its bond holders and equity holders – he recommends a single return on equity to reflect this combined risk.[31] (Id.)

Contrarily, that the AIUs are a combination of gas and electric utilities does not mean that the same cost of equity applies to each of the operations. (Ameren Ex. 36.0 (McShane Reb.), p. 29.) Rather, the return allowed for the electric utility operations should reflect the cost of equity for electric utility operations, and the same goes for the gas operations. (Id.) The combination results in cross-subsidies, erroneous investment decisions, and a misallocation of capital resources. (Id., p. 30.) Like Ms. McShane, Ms. Freetly disagrees with combining the cost of equity and notes that the combination, first, ignores the fact that AIUs' group of gas customers is distinct from its group of electric customers and, further, assumes that the sub-group of customers that take both services effect uniform relative use. (ICC Staff Ex. 20.0 (Freetly Reb.), p. 40.) Ms. Freetly asserts the gas and electric operations must be considered separately to assign the proper rate of return for each entity based on the level of operating and financial risk specific to the operations of each company. (Id.)

Mr. Gorman's sustainable growth DCF study initially ignored the external growth component, and Mr. Gorman disagrees that his failure to include the component resulted in the

[31] If the Commission chooses to determine distinct returns for AIU's electric and gas operations, Mr. Gorman recommends the following: 10.37% and 9.62%, respectively. (IECC Ex. 6.0-C (Gorman Reb.), p. 9.) However, his analyses still underestimate the cost of equity because they do not take into account the higher financial risk of the Ameren Utilities in the ratemaking capital structures relative to the financial risk of the sample companies reflected in their market value capital structures prevailing over the periods relevant to the estimates of the cost of equity (stock prices for DCF and betas for CAPM). (Ameren Ex. 36.0 (McShane Reb.), p. 30.)

understatement of growth rate or DCF results.[32] (IECC Ex. 6.0-C, p. 8.) Mr. Gorman then updated his sustainable growth model to add the component, but he failed to estimate it correctly. (Id., pp. 8-9.) He incorrectly assumed book values per share will increase while stock prices stay the same. (Ameren Ex. 52.0 (McShane Sur.), p. 25.) However, Value Line projects stock prices will also increase, and it is logical that share prices would increase as book values per share increase and as earnings are retained. (Id.) Mr. Gorman's incorrect assumption about stagnant stock prices leads him to incorrectly conclude that the external growth component of the sustainable growth model is negative for the electric sample and minimal for the gas sample. (Id.)

Mr. Gorman criticizes the dividend yield in Ms. McShane's constant growth DCF studies based on his view that her dividend yields are "abnormally high." (IECC Ex. 6.0-C, pp. 6-7.) To conclude the dividend yields are abnormally high, Mr. Gorman compares the recent dividend yield to the average for the past five years. (Ameren Ex. 36.0 (McShane Reb.), p. 20.) However, during much of that 5-year period, the cost of capital was abnormally low, characterized by easy credit, low economic volatility, and a relatively high investor tolerance for risk. (Id.) That landscape has since been altered by the financial crisis of 2008-2009, and the current dividend yields therefore are more representative of their historic average levels. (Id.)

[32] The external financing growth component represents the growth investors expect to achieve through the issuance of additional shares of equity and invested in projects accretive to earnings. (Ameren Ex. 52.0 (McShane Sur.), p. 24.) It represents the impact on earnings and dividends of issuing additional shares of stock at a price above or below book value. (Id.) If a utility is able to issue additional shares at a price above book value, the resulting increase in book value per share will accrue to existing shareholders, leading to higher expected earnings and dividends. (Id.)

Mr. Gorman also challenges Ms. McShane's constant growth DCF because he believes it includes irrationally high growth, and thus, unreasonably inflates AIU's return on equity. (IIEC Ex. 6.0-C, p. 7.) Particularly, he argues that short-term analysts' growth rates in the market today are too high to be reasonable estimates of sustainable long-term growth. (Id.) Mr. Gorman is incorrect, however, because analysts do not make forecasts beyond five years, and therefore, it is not possible to determine whether investors implicitly expect the forecast growth rates to continue indefinitely and when any decline, if any, may occur. (Ameren Ex. 36.0, p. 21.) Accordingly, the constant growth DCF model is the only model that fully retains only objective evidence of investors' growth expectations. (Id.) Results from that model ought to be given at least equal weight to the results of alternative models that incorporate more subjective judgments about investors' regard. (Id.) In addition, Mr. Gorman himself has previously relied on a constant growth DCF result when analysts' forecasts of growth were higher than the expected long-term growth in the economy. (Ameren Ex. 52.0, p. 22.) Thus, there is no reason it is less valid to do so here. (Id.) By discarding his constant growth model results, Mr. Gorman completely substitutes the objective views of analysts with his judgment of what investors view as reasonable and impounded into stock prices. (Ameren Ex. 36.0, p. 21.)

Finally, Mr. Gorman's testimony suggests the Commission should deviate from its precedents when "the Commission has been setting rates in a way that provides the utility an opportunity to recover more than its cost of capital." (Tr. 552.) However, "if rates are set to provide a fair rate of return and provide recovery of the utility's cost of capital based on that theory of return . . . the Commission should continue to follow those policies in setting rates." (Id., p. 551.)

Mr. Thomas's Growth Rate Arguments

Mr. Thomas uses a three-stage DCF test. (CUB Ex. 1.0 (Thomas Dir.), p. 27.) For growth, Mr. Thomas relies on historic growth, due to what he calls the uncertainty in existing analysts' forecasts. (Id.) His analysis assumes, for the short-term, that the sample companies will grow at their average internal growth rate over the last five years. (Id.) For the long-term, he assumes that growth for the sample companies will trend toward the historical average growth rate in real GDP. (Id.) In the final stage, he uses a forecast of real economic growth, rather than nominal growth. (Id.; Ameren Ex. 52.0 (McShane Sur.), p. 31.)

Mr. Thomas's choice of historical period for the first stage is purely subjective and not related to investor expectations embedded in current stock prices. (Ameren Ex. 36.0 (McShane Reb.), p. 33.) With respect to the long-term growth rate, Mr. Thomas's use of a real rate of growth fails to consider that investors require both a real return and compensation for inflation. (Id.) Moreover, the studies Mr. Thomas cites actually analyze actual and forecast growth rates over an extended period of time, reflecting varying levels of inflation rates. These studies do not suggest that the actual nominal rate of long-term growth has been equal to the real rate of growth in the economy or that the expected nominal rates of long-term growth should be equal to the real rate of growth in the economy, and they do not support using a real rate of GDP growth as a proxy for investors' expected long-term growth. (Ameren Ex. 52.0, pp. 31-32.)

Like Mr. Gorman, Mr. Thomas recommends that the Commission place less reliance on analysts' forecasts of growth in the DCF calculation. (CUB Ex. 1.0, p. 16.) He adds that there are other techniques not discussed in this proceeding, which investors use to determine cost of equity; yet, he recognizes that the models used by the Commission are also used by investors. (Tr. 531-33.)

Mr. Thomas argues that, due to discontinuity in the equity markets and uncertainty in information, the Commission should base its analysis of the DCF growth component on three criteria: (1) earnings growth rate inputs that are reasonable in light of anticipated growth in GDP; (2) the long term growth rate must not implicitly require continued earnings above the regulated firm's cost of equity, as derived in the analysis; and (3) the long term growth rates must not require dividend payout ratios that are not consistent with the capital expenditure growth rate and the return on equity. (CUB Ex. 1.0, p. 16.) He argues, incorrectly, that current analysts' 3 to 5 year growth projections do not meet these criteria. (Id.) Rather, he asserts that research demonstrates analysts tend to be optimistic about future growth and produce upwardly-biased forecasts, which translate into DCF costs of capital above the true required cost of capital. (Id., p. 17.) Mr. Thomas reasons that, when companies are expected to have changing dividend payout ratios, the use of forecasted earnings growth rates will not accurately reflect the cost of equity that investors can reasonably expect. (Id., p. 20.) According to Mr. Thomas, Ms. McShane's proposed growth rates would require that the sample companies exceed their own historic growth. (CUB Ex. 2.0 (Thomas Reb.), p. 6.) Yet, the Commission has not previously accepted this argument, as Mr. Thomas admits. (CUB Ex. 1.0, p. 18.) However, the studies that Mr. Thomas cites to support his opinion that analysts are optimistic about future growth rates are less applicable to utilities, and utilities cannot expect similar results. (Ameren Ex. 52.0, p. 31.) And, Ms. Freetly agrees these studies tend to report generalized findings and do not specifically suggest that growth rates for utilities are overstated relative to achieved growth. (ICC Ex. 20.0 (Freetly Reb.), p. 37.) Ms. Freetly also notes other studies that indicate analyst growth rate estimates for utilities are not overstated. (Id.)

Mr. Thomas's cost of equity and fair return are not comparable to any cost of equity or return granted by other regulators, and this is significant because the national average allowed return on equity can be interpreted as a consensus assessment of the expert testimony that has been proffered by a wide range of stakeholders. (Ameren Ex. 52.0, p. 29.) In addition, the national average allowed return on equity is a relevant indicator of the capital markets in which the AIUs will have to compete for capital. (Id.) Returns at the levels proposed by Mr. Thomas are significantly below any reasonable indicator of the returns investors expect to receive on investments of comparable risk. (Id., p. 30.) Such returns would not allow the utilities to attract capital as required on reasonable terms or meet the comparable returns standard. (Ameren Ex. 36.0, p. 30.) And, if the utility is not provided the opportunity to earn a fair and reasonable return, it may be prevented from making the requisite level of investments in the existing infrastructure in order to reliably provide utility services for its customers. (Id., p. 32.)

d. *Beta*

Both Ms. McShane and Mr. Gorman apply Value Line (adjusted, weekly) betas to their CAPM analyses. (Ameren Ex. 36.0 (McShane Reb.), p. 37; IIEC Ex. 6.0-C (Gorman Reb.), p. 5.) In contrast, Ms. Freetly recommends equally weighing weekly and monthly betas because she contends that neither weekly nor monthly betas are superior to the other. (ICC Staff Ex. 20 (Freetly Reb.), p. 34.) She explains that the better type of beta estimate is unclear because both Value Line and regression betas are estimates of the unobservable true beta that measures investors' expectations of the quantity of non-diversifiable risk inherent in a security. (Id., pp.

27-28.) Ms. Freetly argues that her method has been regularly used by both Staff and the Commission and employs the same monthly frequency of stock price data as the widely accepted Merrill Lynch methodology. (Id., p. 28.) She also asserts that the Commission has rejected Ms. McShane's position in a prior proceeding. (Id.)

Ms. Freetly recognizes the strengths of weekly betas but asserts that weekly and monthly betas have strengths and weaknesses relative to each other. She recognizes that the standard of weekly beta estimates is typically lower than that for monthly beta estimates, and thus, weekly betas are usually more reliable. (ICC Staff Ex. 20.0, p. 33.) Yet, she incorrectly argues that non-synchronous trading is a problem with Ms. McShane's weekly data, but for monthly data. (Id., pp. 29-30.) Ms. Freetly also asserts monthly betas are calculated from returns with lower coefficients on variation than weekly betas (which indicates that the variation of weekly returns to the sample mean is subject to increased random error). (Id., pp. 33-34.)

Ms. Freetly is incorrect when she asserts that non-synchronous trading is a problem with weekly betas. The non-synchronous trading effect arises when stock prices respond to economic events with a lag. (Ameren Ex. 52.0 (McShane Sur.), p. 12.) This is a particular problem when analyzing daily data collected on thinly-traded stocks, but it is not a problem here because the Companies are not thinly-traded. (Id., p. 13.) Moreover, Ms. Freetly's analysis that portends to show a statistically significant negative relationship between the lagged returns on the gas utilities and the returns on the equity market composite may actually relate more to the market conditions during the financial crisis than to non-synchronous trading issues. (Id.) Additionally, Ms. Freetly's calculation of the coefficient of variation for the monthly and weekly series of returns does not indicate that there is increased random error in the weekly series relative to the monthly series.[33] (Id.) Rather, higher coefficients of variation associated with weekly betas are consistent with higher weekly betas. (Id., p. 14.)

Ms. Freetly also argues that changes in risk can bias the beta estimate. (ICC Staff Ex. 20.0, p. 33.) Specifically, she asserts that a decrease in a company's systematic risk can increase its estimated beta, and vice versa. (Id.) Thus, according to Ms. Freetly, given the long time period examined in this case, one cannot conclude that the Value Line betas underestimate actual returns or that using monthly returns would have further underestimated the actual returns for gas and electric utilities from those implied betas because the relatively high returns could be a consequence of declining systematic risk. (Id.)

However, greater confidence can be placed in weekly betas because weekly betas are less likely to be impacted by the presence of outlying observations. (Ameren Ex. 36.0, p. 8.) Weekly betas have five times as many observations, thus diluting the impact of observations that are outliers. (Id.) Moreover, regression betas calculated by Staff using monthly data have consistently been lower than the Value Line (weekly) betas. (Id., p. 9.) Ms. McShane performed her own analyses (of both the gas sample and the electric sample) to determine how much more confidence one can have in the betas measured weekly, and her study concludes that much greater confidence can be placed in weekly betas. (Id., pp. 9-12.) Monthly betas, therefore, should be rejected as they are statistically inferior to weekly betas. (Id., p. 12.)

[33] The coefficient of variation is the ratio of the standard deviation of returns to the average return, and it measures the risk per unit of return. (Ameren Ex. 52.0 (McShane Sur.), p. 13.) When it is higher, risk is greater. (Id., pp. 13-14.)

Ms. McShane agrees that the calculated beta may decrease when "true" systematic risk is rising and may increase when "true" systematic risk is falling. (Ameren Ex. 52.0, p. 15.) In such an instance, using the most recent calculated betas tends to understate the cost of equity when systematic risk is rising and vice versa. (Id.) For that very reason, Ms. McShane does not simply compare the most recent betas to the most recently achieved returns for the two samples of utilities. (Id., p. 16.) Instead, she compares a series of calculated betas for both the gas distributors and electric utilities to the average returns to assess whether, over time, the actual returns were in line with what the betas would have predicted. (Id.) Only then did Ms. McShane conclude that the adjusted weekly Value Line betas underestimated the actual returns for both the gas distributors and electric utilities. (Id.)

Ms. Freetly faults Ms. McShane's analysis comparing weekly and monthly betas. (ICC Staff Ex. 20.0 , p. 30). Instead, Ms. Freetly believes Ms. McShane's analysis only tests the predicative ability of the model and does not support the conclusion that monthly betas are statistically inferior to weekly betas. (Id., pp. 30-31.) Ms. Freetly's position, however, is based on her incorrectly emphasizing Ms. McShane's report of the R2 and the t-statistic and downplaying Ms. McShane's comments regarding the standard error.[34] (Ameren Ex. 52.0, p. 14.) Here, standard errors are consistently lower and confidence intervals are consistently narrower for weekly betas, than monthly. (Id.) This demonstrates that the estimates of weekly betas are more precise and dependable than those of monthly betas. (Id., p. 15.)

[34] The standard error measures the precision of the estimated beta: the smaller the standard error, the smaller is the confidence interval and the greater is the confidence that can be placed in the result. (Ameren Ex. 52.0 (McShane Sur.), p. 14.)

Mr. Thomas recommends unadjusted, not Value Line, betas. He asserts there is no evidence to support the rationale for the adjustments – that utility betas trend toward the market mean of 1.0. (CUB Ex. 1.0 (Thomas Dir.), p. 34.) Mr. Thomas argues that utility betas are typically below 1.0; thus, the adjustment improperly increases the betas and the overall CAPM cost of equity. (Id., pp. 34-36. He also cites financial literature purporting to demonstrate that the mean reversion assumption is inappropriate and overstates the beta parameter. (Id.) Accordingly, Mr. Thomas calculates corrected betas by removing the adjustment for each of the companies in his sample groups. (Id., p. 36.)

Mr. Thomas's argument to exclude the adjustment is incorrect. (Ameren Ex. 52.0 (McShane Sur.), p. 32.) There is significant empirical evidence indicating that "raw" or unadjusted betas underestimate the returns of low beta stocks and overestimate returns of high beta stocks. (Id.) The adjustment corrects for the empirically observed relationships between betas and returns. (Id.) Therefore, the adjusted Value Line betas are better predictors of utility returns than unadjusted betas. (Id.) In fact, even Mr. Thomas admits that the "Commission has accepted a static [beta] adjustment without question in the past, although there is absolutely no evidence that a one-size fits all adjustment is reasonable." (CUB Ex. 2.0 (Thomas Reb.), p. 8.) Ms. Freetly agrees betas should be adjusted. (ICC Staff Ex. 20.0 (Freetly Reb.), p. 38.) She recognizes that even the text cited by Mr. Thomas concedes that adjustments result in "appreciably better forecasts," and she cites additional sources to show that Mr. Thomas's proposal has been explicitly rejected in prior studies. (Id., pp. 38-39.)

e. *Market Risk Premium*

The CAPM requires determining the equity risk premium required for the market as a whole ("market risk premium"), then adjusting it to account for the risk of the particular security or portfolio of securities using the beta.[35] The result (market risk premium multiplied by beta) is an estimate of the equity risk premium specific to the particular security or portfolio of securities. (See, e.g., AmerenCIPS Ex. 12.0E (McShane Dir.), p. 42.) The required market risk premium varies with the outlook for inflation and other economic and capital market conditions, interest rates, investors' willingness to bear risk, and profits. (Id., pp. 45-46.)

The required market equity risk premium can be developed (1) from estimates of prospective market risk premiums and (2) from an analysis of experienced market risk premiums. (See, e.g., AmerenCIPS Ex. 12.0E (McShane Dir.), p. 45.) The DCF model can be used to estimate the cost of equity where the expected return is comprised of the dividend yield plus investor expectations of longer-term growth based on prevailing capital market conditions. (Id.) For the DCF-based market risk premium, an estimate of a forward-looking market risk premium is valuable. (Id., pp. 46-47.) This is because the required market risk premium is not static, and thus, a direct measure of the prospective market risk premium may provide a more accurate measure of the current level of the expected differential between stock and bond returns than experienced risk premiums. (Id., p. 46.) An estimate of a forward-looking market risk premium provides value because 1) the equivalence of past return to what were investors'

[35] Mr. Thomas believes that, due to problems with the CAPM model, it should be used only as a check on the results of the DCF model. (CUB Ex. 1.0 (Thomas Dir.), p.32.) Thus, he argues that, if the Commission believes the CAPM is valuable, it should use his results to find that the cost of equity for the AIUs should be at the lower end of any range of valid estimates. (Id., p. 44.) The results of Mr. Thomas's CAPM analysis produce a range of 7.39% to 11.16% for the electric sample and 5.85% to 10.71% for the gas sample. (Id., p. 43.) However, this results in flawed returns on equity that are barely above the long-term cost of debt for the utilities. (Ameren Ex. 36.0 (McShane Reb.), p. 33.)

ex ante expectations may be pure coincidence and 2) the determination of a fair return on equity reflective of the expected interest rate environment requires a direct assessment of current stock market expectations. (Id.)

The forward-looking market premium may be determined by an application of the DCF model to the S&P 500. (AmerenCIPS Ex. 12.0E (McShane Dir.), p. 46.) To estimate the DCF cost of equity for the S&P 500, an expected dividend yield and an expected growth rate are required. (Id., pp. 46-47.) The expected dividend yield is equal to the average of the month-end February and March 2009 market-value weighted expected dividend yields for the S&P 500 companies of 3.7%. (Id., p. 47.) For the expected growth rate, the market-value weighted consensus forecasts of earnings growth for the companies in the S&P 500 were used as a proxy for investor expectations of long-term growth. (Id.) For the risk-free rate, Ms. McShane uses the forecast 30-year Treasury yield expected to prevail over the same five-year time frame for which the forecast growth rates for the market are made. (Id.) The use of the five-year forecast also recognizes that current government bond yields are abnormally low. (Id.)

Because the equity markets are currently experiencing significant turmoil and uncertainty, Ms. McShane recommends giving greater weight to the DCF-based market risk premium than she has in the past. (AmerenCIPS Ex. 12.0E (McShane Dir.), p.47.) Given the extent of equity market risk at present, the current level of the market risk premium is higher by a significant margin than its long-term average. (Id., pp. 47-48.) Accordingly, Ms. McShane made two CAPM estimates of the cost of equity – one based on *ex post* market risk premiums and one based on an *ex ante* estimate of the market risk premium. (Id., p. 48.)

Based on the DCF-based market risk premium (applied to the sample beta), the forward-looking estimate of the CAPM market risk premium amounts to 6.8%. (Ameren Ex. 36.0 (McShane Reb.), p. 37.) By applying the DCF model to the S&P 500, based on a dividend yield for S&P 500 of 2.1% and a consensus I/B/E/S forecast of five-year growth of 9.63%, the resulting expected market return produced by the *ex ante* DCF-based market risk premium approach is 12.0%. (Id.) The CAPM return on equity produced by the *ex post* market risk premium approach is 9.7% for the gas sample and 10.3% for the electric sample. (Id.) Because the DCF-based market risk premium approach explicitly captures current financial market conditions, Ms. McShane recommends that the CAPM return on equity produced by the *ex ante* DCF-based market risk premium approach be given greater weight than the CAPM return on equity produced by the *ex post* (or historic) market risk premium approach. (AmerenCIPS Ex. 12.0E (McShane Dir.), p. 53.)

The estimation of the expected market risk premium from achieved (*ex post*) market risk premiums is premised on the notion that investors' expectations are linked to their past experience. (AmerenCIPS Ex. 12.0E (McShane Dir.), p. 48.) Basing calculations of achieved risk premiums on the longest periods available reflects the notion that it is necessary to include as broad a range of event types as possible to avoid overweighing periods that represent unusual circumstances. (Id.) Since the objective of the analysis is to assess investor expectations in the current economic and capital market environment, weight should be given to periods whose equity characteristics are more closely aligned with what today's investors are likely to anticipate over the longer term. (Id.) When an estimated market risk premium is developed from historic average returns, arithmetic averages need to be used, and the income return –

not the total return on long-term government bonds – should be the measure of the historic risk-free rate used when calculating historic risk premiums. (Id., pp. 48-50.) The income return is appropriate because the CAPM requires a riskless return. (Id., p. 50.)

Ms. McShane also performs an equity risk premium test based on utility achieved risk premiums.[36] (AmerenCIPS Ex. 12.0E (McShane Dir.), p. 53.) Reliance on achieved risk premiums for the utility industries as an indicator of what investors expect for the future is based on the same proposition as that used in the development of the market risk premium – over the longer term, investors' expectations and experience converge. (Id.) The more stable an industry, the more likely it is that this convergence will occur. (Id.)

Ms. McShane also estimated the historic equity risk premiums for utilities relative to long-term A-rated public utility bonds and BAA-rated public utility bonds. (Ameren Ex. 36.0 (McShane Reb.), p. 38.) She estimated the historic equity risk premium for utilities relative to long-term A-rated public utility bonds and Baa-rated public utility bonds at 4.5% and 4.25% respectively. (Id.) Adding the historic spreads between the utility and bond yields to the long-term Treasury yield of 5.5% results in a forecast A-rated utility bond yield of 6.8% and a Baa-rated utility bond yield of 7.2%. (Id.) The resulting required equity returns are 11.3% and 11.5% for the gas and electric samples respectively. (Id.)

[36] Ms. McShane estimated the historic CAPM return on equity at 9.8% for the gas sample and 10.4% for the electric sample. (Ameren Ex. 36.0 (McShane Reb.), p. 38.) Her historic utility risk premium cost of equity is estimated at 11.0%. (Id.) She also performed a DCF-based equity risk premium test for the utilities. She calculates that the required equity return as applied to the proxy sample of natural gas LDCs is approximately 10.2% and, for the electric utilities, approximately 11.1%. (Id., p. 39.) Mr. Thomas rejects Ms. McShane's risk premium methods, other than the CAPM, because he asserts the "Commission has historically rejected risk premium analysis other then the CAPM." (CUB Ex. 1.0 (Thomas Dir.), p. 44.)

Ms. Freetly also conducts a CAPM test.[37] For the risk-free rate of return, she examines the suitability of the yields on four-week U.S. Treasury bills and 30-year U.S. Treasury bonds. (ICC Staff Ex. 6.0 (Freetly Dir.), p. 13.) She uses a 4.4% "spot" 30-year Treasury yield in deriving her CAPM estimate. Ms. Freetly then estimates the expected rate of return on the market by conducting a DCF analysis on the firms composing the S&P 500 as of June 30, 2009. (Id., p. 17.) Ms. Freetly's CAPM test estimates the following rates of return on common equity: For the gas sample, 9.46%, and for the electric sample, 10.21%. (ICC Staff Ex. 20.0 (Freetly Reb.), Schedule 20.02.)

As noted, for the risk-free rate, Ms. McShane advocates using a longer-term Treasury, to more closely match the duration of the risk-free rate and common equities, whose values reflect expected cash flows that are perpetual in nature. (AmerenCIPS Ex. 12.0E (McShane Dir.), pp. 42-43.) Most analysts rely on a long-term government yield, which is risk-free in that there is no default risk associated with U.S. Treasury securities. (Id., p. 43.) Accordingly, Ms. McShane utilizes forecast yields on the 30-year Treasury bond for two reasons: First, the duration of the 30-year Treasury bond more closely matches the perpetual life of equities; second, although the federal government stopped issuing 30-year bonds in 2002, it began issuing them again in 2006, and it will likely continue to do so in light of significant government deficits created in recent months. (Id., p. 43.) The 30-year Treasury bond is once again considered a benchmark bond for the purpose of pricing securities. (Id.)

[37] Mr. Gorman argues Ms. Freetly's market risk premium is not reasonable because her DCF-derived return (12.70%) is not a reasonable and accurate estimate of a DCF return on the market. (IIEC Ex. 6.0 (Gorman Reb.), p. 14.) He asserts that her return estimate reflects a growth rate of over 11%, which is more than twice the expected long-term growth rate of the U.S. GDP. (Id.)

Ms. Freetly criticizes Ms. McShane's use of historical data in developing her market and utility equity risk premiums. (ICC Staff Ex. 6.0 (Freetly Dir.), p. 48.) Yet, it is unreasonable to expect investors to ignore returns they have achieved historically when forming their equity market return expectations going forward. (Ameren Ex. 36.0 (McShane Reb.), p. 41.) Without a discernable trend in achieved returns over time, as is the case here, historic returns provide a relevant perspective on the returns investors may reasonably expect over the longer-term. (Id.) The best estimate of the expected value of a variable that has behaved randomly in the past is the arithmetic mean of its past values. (Id., p. 42.)

Mr. Gorman's CAPM analysis is inappropriate based on his market risk premium. Mr. Gorman makes two estimates of the market risk premium: a forward-looking estimate and an estimate based on a long-term historical average. (IIEC Ex. 2.0 (Gorman Dir.), p. 44.) In his rebuttal, however, though he claims to disagree with "most of her arguments," Mr. Gorman's CAPM estimates reflect Ms. McShane's proposed modifications to his market risk premium estimate. (IIEC ex. 6.0-C (Gorman Reb.), p. 5.)

Yet, Mr. Gorman's risk premium method also incorrectly estimates the market return by adding an estimate of the long-term rate of inflation to the historic average real return. (Ameren Ex. 52.0 (McShane Sur.) at 27.) The real return should be correlated with historical stock returns, and Mr. Gorman does not do so. (Id.; IIEC Ex. 6.0-C (Gorman Reb.) at 10.) As inflation is lower, the real return is higher, and inflation is expected to be lower going forward than it has been historically. (Ameren Ex. 52.0 (McShane Sur.), p. 27.) The higher experienced real returns at lower rates of inflation suggest that using a long-term average real return to estimate the future market risk premium will understate a reasonable estimate of the future equity market return and underestimate the equity market risk premium. (Id.) Combining the average real return achieved on the market with expected inflation would be appropriate only if there were evidence that the expected return on the market moves in tandem with the rate of inflation. (Ameren Ex. 36.0 (McShane Reb.), p. 24.) There is no such evidence, and there has been no positive correlation between inflation and actual market returns historically. (Id.) Rather, equity markets have been generally higher when inflation was lower. (Id.)

Mr. Gorman's evidence on the market risk premium also does not address the fact that the historic measured risk premiums through 2008 were negatively impacted by the significant sell-off in the equity market in 2008. (Ameren Ex. 52.0 (McShane Sur.), p. 27.) The 2009 upswing in the equity market, through the end of October, indicates a higher measured equity market risk premium than did the values calculated through the end of 2008. (Id.) Thus, Mr. Gorman's estimate of the market risk premium and resulting CAPM costs of equity are too low. (Id., p. 28.)

To support his risk premium estimate, Gorman also performs a multi-stage DCF model. However, his model assumes investors expect that analysts' forecasts of growth will persist for ten years and that growth will then drop precipitously to the expected nominal rate of growth in the economy. (Ameren Ex. 36.0 (McShane Reb.), p. 28.) The result of Mr. Gorman's model is well below his multi-stage DCF estimates for both the electric and gas samples. (Id.) This does not help assess the reasonableness of Mr. Gorman's equity market risk premium estimate.

Mr. Gorman criticizes Ms. McShane's risk premium studies for two reasons. First, he criticizes her use of long-term forecasts of interest rates in conjunction with her historic risk premiums and asserts that only interest rates expected to prevail over the period should be used. (Ameren Ex. 36.0 (McShane Reb.), pp. 43-44.) However, when conducting her equity risk premium tests by reference to historic average returns and risk premiums for both the market as a whole and for utilities, Ms. McShane combines a long-term average risk premium with long-term average expected bond yields. (Id., p. 43.) Using historical average risk premiums to develop a forward looking cost of equity assumes that the risk premium will be constant over a business or interest rate cycle; yet, the equity risk premium varies over the cycle, depending on the economy. (Id., p. 44.) Thus, the combination of a historic risk premium with a spot interest rate will result in an under- or over-estimation of the cost of equity at any given point in time. (Id.) Ms. McShane's approach of combining a forecast long-term average interest rate with the long-term average risk premium produces an estimate of the cost of equity that matches the constancy of the equity risk premium implied by the use of historic averages with a similarly estimated interest rate. (Id., p. 44.)

Second, Mr. Gorman criticizes Ms. McShane's use of forecasts of utility bond yields, particularly in her application of the equity risk premium tests. However, Mr. Gorman himself uses forecasts of long-term Treasury interest rates in his CAPM, which is comparable to Ms. McShane's use of forecasts of utility bond yields. (Ameren Ex. 36.0 (McShane Reb.), p. 44.) As the economy recovers, if long-term Treasury bond yields are expected to rise, so will utility bond yields. (Id.) Thus, Ms. McShane's analysis correctly incorporates the impact of the expected increase in long-term Treasury bond yields on the corresponding utility bond yields. (Id.) Finally, it is true that, generally, the recent Treasury and utility bond yields are more aligned with levels over the past five years and that utility dividend yields are typically higher when utility bond yields are higher. (Ameren Ex. 52.0 (McShane Sur.), p. 23.) However, the relationship between utility bond yields and utility dividend yields varies considerably. (Id.)

Ms. Freetly and Mr. Gorman also recommend that the Commission use current interest rates ("spot" interest rates) rather than forecast interest rates in Ms. McShane's risk premium studies. Specifically, to estimate the risk-free rate, Ms. Freetly used current U.S. Treasury yields that she asserts reflect all relevant, currently available information, including investor expectations regarding future interest rates. (ICC Staff Ex. 20.0 (Freetly Reb.), p. 34.) Ms. Freetly asserts that investor appraisals of the value of forecasts are reflected in current interest rates, and therefore, if investors believe that the forecasts are valuable, that belief would be reflected in current market interest rates. (Id.)

However, "spot" Treasury yields remain at relatively low levels as a result of several factors, including the global demand for U.S. Treasury debt and relatively weak economic conditions. (Ameren Ex. 52.0 (McShane Sur.), p. 11.) With the U.S. federal budget deficit for 2009 topping $1.4 trillion, the most likely trajectory for U.S. Treasury bond yields, as the U.S. global economies strengthen, is an upward trajectory. (Id.) Such an upward trajectory is reflected in the consensus of economists' forecasts, which recognize that interest rates will rise as the economy improves. (Id.) Therefore, the application of the CAPM – a forward-looking estimate of the cost of equity – should recognize the high probability that U.S Treasury yields will increase. (Id.) "Spot" interest rates are therefore not appropriate.

According to Mr. Gorman, Ms. McShane's market risk premium estimated from historic data is overstated because it relies on income returns rather than on total returns on Treasury bonds. (Ameren Ex. 52.0 (McShane Sur.), p. 26; IIEC Ex. 6.0-C (Gorman Reb.), p. 11.) He argues

Ms. McShane's analysis is flawed because she uses Morningstar data, which he asserts overstate the market risk premium that would be measured from total Treasury bond returns because Morningstar risk premiums are measured using the Treasury bond income returns. (IECC Ex. 6.0 (Gorman Reb.) at 11.) Ms. McShane agrees that the estimated risk premium using income returns on Treasury bonds is higher than it would be if it were measured using total returns. (Ameren Ex. 36.0 (McShane Sur.), p. 26.) However, Mr. Gorman ignores the fact that proper application of CAPM requires a risk-free rate. (Id.) And, the total returns on bonds are not a measure of risk-free rate. (Id.) Thus, the income return is the best representation of the true long-term historical risk free rate. (Id.)

Mr. Thomas argues that an expected market risk premium of 5% may be too high. (CUB Ex. 2.0 (Thomas Reb.), p. 8.) Rather, he asserts current academic research looking at post-crisis equity premiums demonstrates that current r estimates range from 3.4% to 5.1%. (Id., pp. 8-9.) Contrary to Mr. Thomas's opinion, there is no reason to conclude that equity market returns will be lower in the future than they were in the past. (Ameren Ex. 52.0 (McShane Sur.), p. 33.) Historic evidence alone supports an equity risk premium equal to or slightly higher than 6.5%. (Id.) In addition, as Ms. Freetly asserts, because the relationship between returns of the stock market and U.S. Treasury bonds is not stable over time, current returns provide the best indication of what investors are expecting going forward. (ICC Ex. 20. (Freetly Reb.), pp. 39-40.) Furthermore, Ms. Freetly disagrees that the proper expected common equity market risk premium for determining the investor-required rate of return is between 3 and 5%. (Id. at 39.)

Mr. Thomas also advocates that the *ex post* calculation for a particular rate case is unlikely to produce a result superior to one drawn from years of research by the financial and academic communities. (CUB Ex. 1.0 (Thomas Dir.), p. 39.) He cites several studies and surveys indicating that historic stock market data is upwardly biased. (Id., pp. 40-41.)

f. *Proposed Adjustments*

(1) Financial Risk

To determine a fair return on equity for a utility, it is vital to recognize that the cost of capital is determined in the capital markets and reflects the market value of firms' debt and equity capital. (AmerenCIPS Ex. 12.0E (McShane Dir.), p. 60.) Market value capital structures may differ from book value capital structures. (Id.) When the market value common equity ratio is higher (lower) than the book value common equity ratio, the market is attributing less (more) financial risk to the firm than is "on the books" as measured by the book value capital structure. (Id.) Higher financial risk leads to a higher cost of common equity, all other things equal. (Id.) Thus, the cost of equity estimated using the sample utilities must be increased when applied to a lower ratemaking book value common equity ratio, and vice versa. (Id., p. 61.)

Both Ameren and Staff agree that a market-based cost of equity is appropriate and that it is necessary to use a book value rate base for regulatory rate setting. (Ameren Ex. 52.0 (McShane Sur.), p. 16; ICC Staff Ex. 20.0 (Freetly Reb.), p. 36.) In addition, both agree that differences in financial risk must be accounted for in the cost of equity and that higher or lower financial risk than the proxy companies, given similar business risk, requires an adjustment to the proxy companies' costs of equity. (Id., p. 17.) The issue is not *whether* an adjustment for financial risk differences is required, but rather, *how* to measure those differences. (Id.)

Ms. McShane uses two approaches to quantify the impact of a change in financial risk on the cost of equity. (AmerenCIPS Ex. 12.0E (McShane Dir.), p. 63.) Her first approach is based on the widely accepted view that the overall cost of capital does not change materially over a relatively broad range of capital structures. (Id.) Her second approach is based on the theoretical model that assumes that the overall cost of capital declines as the debt ratio rises due to the income tax shield on interest expense. (Id.) The latter approach will overestimate the impact of leverage on the overall cost of capital and understate the impact of increasing financial leverage on the cost of equity because that approach does not account for any of the factors that offset the corporate income tax advantage of debt. (Id.)

To apply these approaches, Ms. McShane first determines the market value capital structures of the sample companies over the period corresponding to the relevant period of analysis for the specific cost of equity. (AmerenCIPS Ex. 12.0E (McShane Dir.), p. 64.) Then, she estimates the utility samples' weighted average cost of capital using market value capital structures and the appropriate market value common equity ratio and cost of equity. (Id., p. 65.) Finally, she estimates the change in common equity return requirement for each of her tests (DCF, CAPM, and DCF-based risk premium tests) to account for the difference between the sample average market value common equity ratio and the company's book value common equity ratio. (Id., p. 66.) If the difference between the company's ratemaking common equity ratio and the relevant market value common equity ratios results in an adjustment, Ms. McShane recommends that the allowed return on equity be adjusted accordingly. (See, e.g., AmerenCIPS Ex. 12.0G (McShane Dir.), p. 68.) Ms. McShane's method has been accepted by other regulators in the past. (Id., pp. 67-68.)

In the past, the Commission has rejected Ms. McShane's approach because the AIUs do not have market traded stock. However, applying a market-derived cost of equity to the book value (ratemaking) capital structure without recognizing the financial risk differences between the market value capital structures that underpin the estimates of the cost of equity and the book value (ratemaking) capital structures of the AIU utilities will understate the AIUs' cost of equity. (AmerenCIPS Ex. 12.0E (McShane Dir.), p. 67.) The lack of observable market value capital structures for the AIUs does not alter this conclusion because the relevant comparison is between the financial risk inherent in the market value capital structures of proxy utilities and the financial risk inherent in the book value (ratemaking) capital structures of the AIUs. (Id.)

For each AIU gas utility relative to the gas sample, Ms. Freetly concludes that her revenue requirement recommendations, including her cost of common equity recommendations, indicate levels of financial strength commensurate with a Baa3 credit rating for AmerenCILCO Gas, an A3 credit rating for AmerenCIPS Gas, and a Baa3 credit rating for AmerenIP Gas.[38] (ICC Staff Ex. 20.0, p. 4.) She believes the gas sample's level of financial strength indicates it has more financial risk than AmerenCIPS and less financial risk than AmerenCILCO and AmerenIP. (Id., p. 5.) Given the difference between the credit ratings commensurate with the forward-looking financial strength of the Companies' gas operations and the credit rating commensurate with the gas sample, Ms. Freetly recommends that the

[38] Ms. Freetly explains she could not rely on the Companies' credit ratings, without an investigation of the underlying standalone going forward strength of the Companies, and thus, she did not rely on the current credit ratings of CILCO, CIPS, and IP for comparison to the samples. (ICC Ex. 20.0 (Freetly Reb.), pp. 12-13.) For support, Ms. Freetly notes that the credit ratings: (1) reflect the risk of a company's entire operations, not just those subject to the Commission's rate jurisdiction; (2) could reflect a company's affiliation with other companies; and (3) reflect the credit ratings agency's forecast, which are not published and thus which cannot be compared to Staff's or any other party's revenue requirement recommendations. (Id.)

sample's average cost of common equity be adjusted to determine the estimate of each Company's cost of common equity. (Id. p. 6.) To adjust, Ms. Freetly uses the spreads for 30-year utility debt yields as of August 31, 2009. (Id.) She recommends a 10.5 basis point adjustment for AmerenCILCO and AmerenIP and a decrease of 15 basis points for AmerenCIPS. (Id.) This means a 0.11% increase for AmerenCIPS and AmerenIP, and a 0.15% decrease for AmerenCIPS. (ICC Staff Ex. 20.0, Schedule 20.02.)

For each of the AIUs' electric utilities relative to the electric sample, Ms. Freetly concludes that her revenue requirement recommendations, including cost of common equity recommendations, indicate levels of financial strength commensurate with a Baa1 credit rating for AmerenCILCO, an Aa3 credit rating for AmerenCIPS, and a Baa2 credit rating for AmerenIP. (ICC Staff Ex. 20.0 (Freetly Reb.), p. 8.) According to Ms. Freetly, the electric sample has a lower average implied credit rating, which indicates that its financial risk is higher than that of either AmerenCILCO's or AmerenCIPS's electric delivery service operations. (Id., p. 9.) Given the difference between the implied forward-looking credit ratings for the Companies and the average credit rating of the electric sample, Ms. Freetly recommends that the sample's average cost of common equity be adjusted to determine the estimate of each Company's cost of common equity. (Id., p. 10.) To make the adjustments to the cost of common equity of the electric sample, Ms. Freetly used Reuters Corporate Spreads for Utilities from August 31, 2009. (ICC Staff Ex. 20.0 (Freetly Reb.), p. 10.) Her analysis recommends a cost of equity adjustment for the electric operations of 6 basis points for AmerenCILCO and 30 basis points for AmerenCIPS. (Id., p. 11.) This equates to a 0.06% downward adjustment for AmerenCILCO and a 0.30% downward adjustment for AmerenCIPS. (ICC Staff Ex. 6.0, Schedule 20.02.) Ms. Freetly does not recommend adjusting for AmerenIP because the financial ratios for AmerenIP are commensurate with the same level of financial risk as the electric sample. (Id.)

Ms. Freetly's adjustments are incorrect. Particularly, they are based on the assumption that the AIUs will achieve the credit metrics implicit in Staff's recommendations. (Ameren Ex. 36.0 (McShane Reb.), p. 15.) Moreover, Ms. Freetly claims that Staff's revenue requirement recommendations, including her cost of common equity recommendations, indicate credit metrics commensurate with higher or lower debt ratings than the implied debt ratings suggested by the credit metrics of her utility samples. (Ameren Ex. 52.0 (McShane Sur.), p. 19.) Her comparisons are flawed because she compares credit metrics that her utility samples have actually achieved from 2006-2008 with credit metrics that could be achieved if the AIUs were able to earn the returns on equity that they are allowed. (Id.) Recent history, however, demonstrates the AIUs have significantly under-earned their allowed returns on equity and thus have not achieved the levels of financial strength assumed by Ms. Freetly's financial risk adjustments. (Id.) By comparing the potential financial performance and credit metrics of the AIUs to the actual financial performance and credit metrics of the proxy utilities, Ms. Freetly understates the Ameren Utilities' financial risk relative to the proxy utilities. (Id., p. 20.)

In addition, Ms. Freetly's adjustments assume an equity investor quantifies financial risk differences identically to a bond investor. (Ameren Ex. 36.0 (McShane Reb.), p. 49.) However, proper financial risk adjustments to the cost of equity for the electric and gas samples consider the higher or lower return that equity investors require for bearing the higher or lower financial risk inherent in the AIUs' proposed ratemaking capital structures. (Id.) Ms. Freetly is also incorrect when she contends that Ms. McShane's adjustments would perpetuate further increases in earnings and the market value of the stock. (Id., p. 47.) Earnings, dividends, book, and market values increase at the same rate. (Id., p. 48.) Changes in the market/book ratio should occur only if the cost of capital or the expected return on book equity changes. (Id.) Finally, Ms. Freetly incorrectly refers to Ms. McShane's adjustment for financial risk as a "market-to-book adjustment." (Ameren Ex. 52.0 (McShane Sur.), p. 17.) As discussed, the need to make an adjustment for differences in financial risk is independent of the market-to-book ratio. (Id.)

Mr. Gorman also disagrees with Ms. McShane's financial risk adjustment because he asserts it inflates a fair and reasonable return. (IIEC Ex. 6.0-C (Gorman Reb.), p. 13.) Mr. Thomas disagrees with adjusting the market-based DCF model results before applying them to the book value of assets in rate base, arguing that the adjustment inflates the market-based DCF cost of equity. (CUB Ex. 1.0 (Thomas Dir.), p. 46.) He also claims the Commission has repeatedly concluded that no such adjustment is required. (Id.) However, Mr. Thomas's recommended returns are too low and would deprive AIU of a chance to earn a return commensurate with those of comparable risk firms. (Ameren Ex. 36.0 (McShane Reb.), p. 31.)

(2) Fixed Customer Charge

Ms. Freetly recommends an additional downward adjustment to the gas distribution operations' rate of return on common equity. (ICC Staff Ex. 6.0 (Freetly Dir.), p. 33.) Her adjustment is based on the Commission's recognition, in the AIU's last rate cases, that the AIU gas utilities' move toward more fixed cost recovery – through the fixed monthly charge – gives AIU more assurance of recovering its fixed costs of service for gas operations. (Id., p. 32.) Ms. Freetly contends this cost recovery reduces risk and provides greater assurance that the authorized rate of return will be earned. (Id.) She therefore recommends a downward adjustment of 10 basis points to the AIU gas utilities' rate of return on common equity – the same adjustment the Commission found proper in the last rate cases. (Id., pp. 32-33.)

However, Ms. Freetly disregards the fact that eight of the nine gas distributors in the gas sample have similar mechanisms in place – and thus that the cost of common equity estimate for the sample already reflects the risk reduction. She argues that some of the mechanisms apply only to portions of a company's service territories. (ICC Staff Ex. 20,0 (Freetly Reb.), p. 7.) Nonetheless, if equity investors impute lower risk due to the adoption of such mechanisms, lower risk would already be reflected in the cost of equity estimates for the sample companies. (Ameren Ex. 36.0 (McShane Reb.), p. 17.) Ms. Freetly's recommended reduction would double count the risk reduction that might be imputed by investors and should thus be rejected. (Id.)

(3) Uncollectibles Riders

Ms. Freetly asserts the uncollectible riders would reduce the Companies' risk because they would reduce uncertainty of cash flows. (ICC Staff Ex. 6.0 (Freetly Dir.), p. 38.) Yet, she admits she is unaware of an established approach for gauging the effect that adoption of the riders would have on investor perceptions of the Companies' risk levels and the resulting costs of equity. (Id., p. 39.) Instead, she proposes adjustments for the riders, based on two distinct approaches: (1) estimate the effect of the adoption of the riders on the Companies' Moody's credit ratings, and then, adjust based on the resulting change in implied yield spreads; and (2) adjust cost of common equity downward to offset the increased operating income resulting from the adoption of the riders.[39] (Id., pp. 39-43.) Like Ms. Freetly, Mr. Thomas asserts that the riders will reduce both uncertainty of cash flows and the Companies' risk, and he also is not aware of an approach to gauge the effect of the riders. (CUB Ex. 2.0 (Thomas Reb.), pp. 12-13.) Still, he determines Ms. Freetly's methodology is reasonable, although conservative. (Id.)

For her first approach, Ms. Freetly assumes the credit rating assigned to the "ability to recover costs and earn returns" factor would improve by one credit rating with the implementation of the uncollectibles rider. (ICC Staff Ex. 20.0 (Freetly Reb.), p. 15.) For her second approach, Ms. Freetly adjusts her cost of common equity downward to offset the increased operating income resulting from the adoption of Rider GUA. (ICC Staff Ex. 20.0 (Freetly Reb.), pp. 16-17.) She adjusts her cost of common equity downward until the pro forma operating incomes under Rider GUA equal the original pro forma operating incomes she calculated for the Companies without Rider GUA. (Id., p. 17.) For the electric operations, Ms. Freetly estimates the incremental recovery of uncollectibles expense had Rider EUA been in effect for the past ten years. (Id.) She then adjusts her cost of common equity downward until the pro forma operating incomes under Rider EUA equal the original pro forma operating incomes she calculated for the Companies without Rider EUA. (Id., p. 20.)

[39] In her direct testimony, Ms. Freetly notes the Companies did not provide an estimate of uncollectibles recovery via base rates for the electric service operations. (ICC Ex. 6.0 (Freetly Dir.), p. 43.) In her rebuttal, she asserts the Companies' response to Staff Data Request JF 5.01 did not provide the actual revenue associated with uncollectibles recorded for each of the AIUs' gas and electric utilities in each of the past ten years. (ICC Ex. 20.0 (Freetly Reb.), p. 13.) Thus, she bases her analysis here on the Companies' proposal in Docket No. 09-0399 to compare test year uncollectibles expense with actual Account 904 expense for each period. (Id.)

Ms. Freetly averages the results of her two approaches to determine her recommended adjustments.[40] She recommends adjustments for the electric operations of AmerenCILCO, AmerenCIPS, and AmerenIP of 63, 64.5, and 34 basis points, respectively, to reflect the reduced risk due to Rider EUA; she recommends adjustments to the costs of common equity for the gas operations of AmerenCILCO, AmerenCIPS, and AmerenIP of 87.5, 79.5, and 60.5 basis points, respectively, to reflect the reduced risk due to Rider GUA. (ICC Staff Ex. 20.0 (Freetly Reb.), pp. 20-21.)

Ms. Freetly's approaches are both flawed. In her first approach, Ms. Freetly is incorrect to assume that the credit rating of Moody's "ability to recover costs and earn returns" will increase by one full credit rating: there is no empirical evidence to support that assertion. (Ameren Ex. 52.0 (McShane Sur.), p. 20.) Moreover, where the improved political and regulatory climate in Illinois – which includes the legislation providing Illinois utilities with a bad debt rider – resulted in only a one-notch upgrade in the AIUs' credit ratings, Ms. Freetly's assumption that Moody's would change both the "regulatory framework" and "sustainable profitability" factors by a full credit rating for the adoption of the riders is without merit. (Ameren Ex. 36.0 (McShane Reb.), pp. 17-18.) Moody's already acknowledged the legislation and factored it into its decision to upgrade the Ameren Utilities to investment grade, so the actual adoption of the riders is unlikely to result in a full credit rating improvement in both

[40] Ms. Freetly's method of averaging the two results demonstrates further problems with her analyses. By taking the midpoint, Ms. Freetly follows her view that each method is as likely to accurately reflect the needed adjustment as the other method. (Tr. II, p. 278.) Yet, the numbers resulting from each approach are extremely disparate. (Id.)

regulatory framework and sustainable profitability.[41] (Id., p. 18.) And, even if it did, the AIUs would still have equivalent credit ratings to Ms. Freetly's electric utility operation proxies and lower credit ratings than her gas utility operation proxies. (Id.) Thus, there would be no reason to conclude that, even with the riders, the equity market would view them as less risky than the proxies. (Id.)

Ms. Freetly's second approach is also seriously flawed. It presumes there is an expectation built into the proxy utilities' costs of equity, for when they systematically under-recover bad debt expense. (Ameren Ex. 36.0 (McShane Reb.), pp. 18-19.) However, there is no such evidence here, and thus, no rationale for removing a premium that does not exist. (Id., p. 19.) She necessarily assumed Ameren was more likely to under-recover uncollectible expenses than the sample group; without such an assumption, there can be no adjustment. Yet, Ms. Freetly did not look at the specific under- or over-recovery experience of the proxy utilities for the same ten-year period that she reviewed for the AIUs. (Tr. 275-76.) Thus, she cannot know whether the AIUs face greater risk; she only knows one side of the equation. It is unlikely that all the other companies do better than the AIUs because, as Ms. Freetly admits "that the actual expenses realized aren't always exactly the same as what is in the revenue requirement." (Id., p. 273.)

In addition, this second approach would reduce the return for a risk for which the Ameren Utilities have never been compensated because, as historic evidence shows, risk is not

[41] Ameren witness Mr. Nickloy reiterates that the current ratings of the AIUs reflect the presence of the rider, and thus, no further related ratings upgrade could be expected. (Ameren Ex. 28.0 (Nickloy Reb.), p. 9.) Imposing a revenue/cash flow reduction for the rider can undo the quantitative and qualitative benefits the rider provides in this regard, and in a sense, cancel it out. (Id.)

symmetric and the AIUs have not historically earned more or less than the allowed return. (Ameren Ex. 36.0 (McShane Reb.), p. 19.) Finally, there is no evidence for the relationship between the actual return on equity and the cost of equity. (Id.) Ms. Freetly's assumption – that actual return on equity rises toward the allowed return and the cost of equity falls by an equivalent amount – is false. (Id.)

In addition, Ms. Freetly's downward adjustments for the uncollectible riders are effectively premised on the assumption that the AIUs have similar business risk to the proxy utilities before the adoption of the riders. (Ameren Ex. 52.0 (McShane Sur.), p. 20.) Yet, several factors – including regulatory lag and rising operating costs and capital expenditures – indicate the Ameren Utilities have higher business risk than the proxy companies. (Id., p. 21.) Moreover, a relatively broad sample of gas and electric utilities has higher implied credit ratings on Moody's "regulatory framework" and "ability to recover costs and earn returns" factors than the Ameren Utilities. (Id.) This strongly suggests that Ms. Freetly's implicit point of departure for making her downward adjustments – similar business risk – is incorrect. (Id.)

Ms. Freetly's approach is further flawed because her analyses of each of the AIUs' risk relative to each other (which are then applied to the sample group) make no sense. For example, the adjustment calculated by Ms. Freetly "indicates that the reduction in risk would be higher [for AmerenCILCO than for AmerenIP]," which "indicates that they [AmerenCILCO] do face more uncollectible risk [than AmerenIP]." (Tr. 282.) Yet, based on the metrics applied by Ms. Freetly, relative to the sample group, AmerenCILCO and AmerenIP "have the same indicated level of financial risk," which led her to recommend the same return on equity for each. (Id., pp. 282-283.) Thus, she proposes highly disparate adjustments for two companies that she believes face the same risk. Her adjustments are thus arbitrary and utterly lack the precision they purport to have.

Ms. Freetly fails to respond to these arguments against her adjustments for financial risk. (Ameren Ex. 52.0 (McShane Sur.), p. 20.) She denies that the Moodys' reflection of the bad debt rider legislation eliminates the need to adjust the costs of common equity of the gas and electric samples, but she provides no empirical evidence to support this assertion. (ICC Staff Ex. 20.0 (Freetly Reb.), p. 25.) Ms. Freetly also does not address Ms. McShane's critiques of the "operating income" methodology from which Ms. Freetly estimated large downward adjustments to the proxy samples' costs of equity. (Ameren Ex. 52.0 (McShane Sur.), p. 21.)

Mr. Thomas, too, provides no supporting analysis for his agreement with Ms. Freetly's suggested adjustments for the proposed uncollectibles riders. (Ameren Ex. 52.0 (McShane Sur.), p. 30.) Yet, following the logic of his discussion of Ms. Freetly's proposed adjustments, Mr. Thomas recommends returns at a level significantly below any reasonable indicator of the returns investors expect on investments of comparable risk, including the cost of long-term debt. (Id.; Tr. 529-30.) To explain this odd phenomenon, Mr. Thomas merely attributes it to a "quirk of history" that would lead long-term debt in his proposed capital structure to be costlier than the common equity. (Tr. 530.)

g. *Other*

G. Recommended Overall Rate of Return

The Ameren Illinois Utilities' respective capital structure and cost of capital are summarized in the Tables below:

1. CILCO Electric

Weighted Average Cost of Capital as of 3/31/2009:

CAPITAL COMPONENT	AMOUNT	PERCENT OF TOTAL	COST	WEIGHTED COST
Long-Term Debt	$271,492,364	47.475%	8.161%	3.875%
Short-Term Debt	$32,017,993	5.599%	2.150%	0.120%
Preferred Stock	$18,893,567	3.304%	4.613%	0.152%
Common Equity	$249,457,171	43.622%	11.700%	5.104%
Bank Facility Fees				0.370%
TOTAL	$571,861,095	100.000%		9.621%

2. <u>CIPS Electric</u>

Weighted Average Cost of Capital as of 3/31/2009:

CAPITAL COMPONENT	AMOUNT	PERCENT OF TOTAL	COST	WEIGHTED COST
Long-Term Debt	$397,751,866	40.442%	6.491%	2.625%
Short-Term Debt	$58,098,936	5.907%	1.500%	0.089%
Preferred Stock	$48,974,984	4.980%	5.129%	0.255%
Common Equity	$478,676,606	48.671%	11.300%	5.500%
Bank Facility Fees				0.210%
TOTAL	$983,502,392	100.000%		8.679%

3. <u>IP Electric</u>

Weighted Average Cost of Capital as of 3/31/2009:

CAPITAL COMPONENT	AMOUNT	OF TOTAL	COST	COST
Long-Term Debt	$1,357,044,075	53.768%	7.940%	4.269%
Short-Term Debt	$10,404,002	0.412%	3.020%	0.012%
Preferred Stock	$45,786,945	1.814%	5.010%	0.091%
Common Equity	$1,110,636,039	44.005%	11.700%	5.149%
Bank Facility Fees				0.220%
TOTAL	$2,523,871,061	100.000%		9.741%

4. CILCO Gas

Weighted Average Cost of Capital as of 3/31/2009:

CAPITAL COMPONENT	AMOUNT	OF TOTAL	COST	COST
Long-Term Debt	$271,492,364	47.475%	8.161%	3.875%
Short-Term Debt	$32,017,993	5.599%	2.150%	0.120%
Preferred Stock	$18,893,567	3.304%	4.613%	0.152%
Common Equity	$249,457,171	43.622%	11.200%	4.886%
Bank Facility Fees				0.370%
TOTAL	$571,861,095	100.000%		9.403%

5. CIPS Gas

Weighted Average Cost of Capital as of 3/31/2009:

CAPITAL COMPONENT	AMOUNT	OF TOTAL	COST	COST
Long-Term Debt	$397,751,866	40.442%	6.491%	2.625%
Short-Term Debt	$58,098,936	5.907%	1.500%	0.089%
Preferred Stock	$48,974,984	4.980%	5.129%	0.255%
Common Equity	$478,676,606	48.671%	10.800%	5.256%
Bank Facility Fees				0.210%
TOTAL	$983,502,392	100.000%		8.435%

6. IP Gas

Weighted Average Cost of Capital as of 3/31/2009:

CAPITAL COMPONENT	AMOUNT	OF TOTAL	COST	COST
Long-Term Debt	$1,357,044,075	53.768%	7.940%	4.269%
Short-Term Debt	$10,404,002	0.412%	3.020%	0.012%
Preferred Stock	$45,786,945	1.814%	5.010%	0.091%
Common Equity	$1,110,636,039	44.005%	11.200%	4.929%
Bank Facility Fees				0.220%
TOTAL	$2,523,871,061	100.000%		9.521%

V. PROPOSED RIDERS

A. Overview

B. Resolved Issues

1. Revisions to Rider S for PGA Uncollectibles

In the last rate cases, the Commission directed the AIUs to remove the uncollectible expense component associated with the PGA from the gas delivery service base rates paid by transport customers served under Rider T. (Ameren Ex. 17.0G (Rev.), p. 17.) In response to this directive, the AIUs propose to unbundle PGA-related uncollectible expenses and incorporate those expenses into Rider S with class-specific uncollectible recovery factors that will apply to the PGA charge components. (*See* Ameren Ex 1.0G, p. 16; Ameren Ex 2.0G, p. 30; Ameren Ex. 17.0G (Rev.), pp. 17-19.) This will provide more precision in ratemaking by segregating delivery costs from purchased gas costs and provide a better matching of revenue and uncollectibles expense. (Ameren Ex 1.0G, p. 16.) Staff supports this recovery mechanism. (ICC Staff Ex. 1.0, pp. 37-38.)

The AIUs initially calculated the Rider S uncollectibles factors using a three-year average of the comparison of net write-offs with gas revenues for the period 2007 through 2009. (Ameren Ex. 2.4, Schedule 3.) Staff supported the use of a three-year average to determine the uncollectible factor. (Id.) Staff, however, objected to using projected 2009 amounts in the 3-year average. (Id.) Instead, Staff recommended that the AIUs calculate the average using only the actual (not projected) data from 2006 through 2008. (Id.; ICC Staff Ex. 1.0, Schedules 1.12 CILCO-G, 1.12 CIPS-G, and 1.12 IP-G.)

In an effort to minimize the issues in this proceeding, the AIUs modified their calculation of PGA uncollectibles factors for Rider S so that it now uses only the most recent actual information for the period January 2007 through September 2009. (Ameren Ex. 29.0 (Rev.), p.9; Ameren Ex. 29.4.) Ameren witness Millburg provided revised PGA uncollectibles factors that are based entirely on actual information. (Ameren Ex. 48.0 (Rev.), p. 8.) The AIUs propose to incorporate those proposed PGA uncollectibles factors into Rider S on Sheet 24.001 of their Gas Services Tariffs. (Id.) The AIU's agreement to revise the calculation of the PGA uncollectibles factors addresses Staff's concerns because the new calculation is based entirely on actual information – not projections. (Ameren Ex. 29.0 Rev., p. 9.) Staff did not address the revised Rider S PGA uncollectibles factors in rebuttal testimony. The AIUs, therefore, believe the issue of unbundling PGA Uncollectibles using Rider S is a resolved issue. The Commission should approve the revised PGA uncollectibles factors proposed by Ameren witness Millburg.

2. Exclusion of Electric Distribution Tax/Public Utilities Revenue Act Tax from Tax Additions Rider

The AIU no longer seek approval to implement a tax additions rider to recover distribution tax revenue in this docket. (See Section VII (C)(2)(c) infra.)

C. Contested Issues

1. Rider VGP

The AIUs propose a new tariff for the Commission's approval. This tariff – the Voluntary Green Program ("Rider VGP") – will apply to electric delivery service customers interested in financially supporting the development of renewable energy technologies. (Ameren Ex. 14.0E (Mill Dir.), p. 2.) If approved, Rider VGP is another means to promote the federal and state policy for cleaner, renewable energy. (Id., p. 6.) The AIUs also request the Commission acknowledge, in its Final Order, that the AIUs' offering and promotion of their proposed Rider VGP to delivery service customers will not be deemed a violation of the Commission's Integrated Distribution Company ("IDC") rule as set forth in 83 Ill. Adm. Code Part 452.230, Permissible and Impermissible Integrated Distribution Company Services. (Id., p. 2.) Because participation in Rider VGP does not alter the amount of energy and power supply commodity purchased by a customer, nor does it limit or alter the customer's energy and power supply options, the offering of Rider VGP pursuant to the proposed tariff should not violate IDC rules. (Id., pp. 8-9.) Finally, if approved, the AIUs propose the rider begin 60 days from the date of service of the Final Order. (Id., p. 9.)

The proposed program is REC-based, meaning there is no renewable power and energy commodity provided to participants. (Ameren Ex. 14.0E (Mill Dir.), p. 6.) Unlike power and energy, which are physical commodities, a REC cannot power homes or businesses; rather, a REC reflects the environmental intangible attributes of electricity already generated from a renewable resource.[42] (Id., p. 7.) RECs have been accepted by the Illinois Power Agency and the Commission as an appropriate method for complying with Illinois renewable energy requirements. (Id.)

The AIUs' plan is to purchase RECs with revenue received from program participants. (Ameren Ex. 14.0E (Mill Dir.), p. 7.) To offset out-of-pocket and other incremental costs, the AIUs are proposing to mark-up the actual cost of the program RECs by 5%, not to exceed $1 per

[42] A REC represents the environmental attribute of one megawatt-hour of power produced from a renewable energy project and is sold separately from the actual electricity commodity. (Ameren Ex. 1.0E (Nelson Dir.), p. 15.)

REC.[43] (Id., pp. 7-8.) Subsequent to each month, the AIUs will use the proceeds received from program participants, less administrative mark-up, to purchase the corresponding number of RECs on behalf of participating customers. (Ameren Ex. 39.0 Rev. (Mill Reb.), p. 2.) It is important for program participants and the AIUs to know the REC prices in advance of customer participation. (Id.) The planned approach is for the customer to select its own level of participation: residential participants would select one of three monthly contribution levels ($3, $7, or $15), and non-residential customers would elect the number of RECs they wish to purchase each month. (Ameren Ex. 14.0E, pp. 6-7.) As provided in response to ICC Staff data request RJZ 1.03, the AIUs will use a single round, pay as bid RFP process to acquire RECs for the program and will seek price certainty for RECs for an extended number of months, if not a year at a time. (Ameren Ex. 39.0, p. 4.) The RFP process would be administered directly by the AIUs and advertised in trade publications for broad exposure. (Id.)

The AIUs are still attempting to determine the initial REC quantity. (Ameren Ex. 39.0 Rev. (Mill Reb.), p. 5.) The AIUs propose flexibility regarding for the REC procurement process because this program is new and the AIUs cannot predict the number of customers signing up or the financial level at which those customers wish to participate. (Ameren Ex. 67.0 (Mill Sur.), p. 5.) Moreover, the AIUs plan to seek REC procurement terms that will keep REC costs reasonable and also allow as much flexibility as possible regarding the number of RECs, timing of REC payments, and deliveries. (Id.) A flexible pay-as-you-go approach is desired, but that must be balanced with the overall price of RECs under such arrangement and the willingness of

[43] The AIUs reserve judgment to later request additional cost recovery in this case if modifications are required, or in the next rate cases if more costs are incurred than expected. (Ameren Ex. 14.0E (Mill Dir.), p. 8.)

REC suppliers to sell under those terms. (Id.) It would be premature for the AIUs to begin its REC procurement process prior to the Final Order approving Rider VGP. (Id., p. 3.) The AIUs' preferred approach for contracting the purchase of program RECs would be to pay the supplier for RECs with proceeds collected from VGP participants. (Id.) However, it is possible the AIUs will be required to prepay for RECs before program participants pay for them, since the AIUs cannot predict the pace of customer sign-up, participation levels, and payment levels. (Id.) The AIUs must be cautious that overly restrictive REC procurement requirements may limit the number of bidders or result in paying premium prices for the RECs. (Id.)

The AIUs believe it is important for program success to have stable REC prices for a year at a time. (Ameren Ex. 39.0 Rev. (Mill Reb.), p. 5.) While the goal is to keep REC prices fixed for annual periods, the AIUs will not make such a commitment to participants. (Id.) Since the AIUs cannot accurately predict participation levels, they intend to update the cost of such RECs as they are procured from time to time. (Id.) The AIUs also intend to make retirement of the RECs the responsibility of the REC supplier. (Id.) The AIUs role would be to (1) accumulate the quantity of REC purchased under the program, at the end of the month, (2) notify the REC supplier of the quantity to be retired in the AIUs' name, and (3) review documentation provided by the supplier to verify the appropriate quantity was retired in the AIUs' name. (Id.)

The AIUs' procurement objective would be to spread delivery and payment for the RECs (actually delivery of RECs retired on behalf of VGP participation) over an annual period, meaning the AIUs may be required to prepay for some amount of RECs prior to collecting VGP payments from participants. (Ameren Ex. 67.0 (Mill Sur.), p. 4.) The AIUs may also have to purchase RECs at a faster pace than planned if program sign-ups exceed the monthly REC supply. (Id.) The accounting entries present in Ameren Exhibit 39.1 were intended to provide accounting entry detail to cover a REC prepayment scenario as well as a pay-as-you-go REC procurement scenario. (Id.)

The AIUs will prepare internal reports on Rider VGP program activity to provide a transparent accounting for the program revenues, RECs, and incremental costs. (Ameren Ex. 39.0 Rev. (Mill Reb.), pp. 2-3.) Additionally, in response to ICC Staff data request RJZ 1.05, the AIUs explained it would procure RECs from resources located within the MISO or PJM regional transmission organization areas. (Id., p. 4.) The AIUs will rely on the same criteria for Rider VGP RECs, set forth in Public Act 095-0481, regarding RECs for the Illinois Statewide Renewable Portfolio Standard. (Id.) To ICC Staff data request RJZ 1.09, the AIUs responded they plan to adapt a version of the REC contract used for their 2009 Illinois Power Agency Procurement. (Id.)

The incremental costs of implementing Rider VGP are expected to be minimal. (Ameren Ex. 14.0E (Mill Dir.), p. 7.) The AIUs already have infrastructure in place to administer the program, channels to promote it, internal expertise to acquire and manage the RECs and to educate customers, and a capable billing system. (Id., pp. 3, 7.) The AIUs intend to use current AIUs information channels and emerging communication avenues to publicize Rider VGP. (Ameren Ex. 39.0 Rev. (Mill Reb.), p. 3.) No additional costs have been built into the revenue requirement in this case for administering the proposed program. (Ameren Ex. 14.0, p. 7.)

In addition to promoting cleaner, renewable energy, the AIUs offer the voluntary green program due to delivery service customers that have an interest in supporting renewable energy technologies through programs similar to that proposed in Rider VGP. (Ameren Ex.

14.0E (Mill Dir.), p. 3.) For one, AIUs customers, especially those residing in the St. Louis metropolitan area, have expressed interest in participating in Union Electric Company d/b/a AmerenUE's ("AmerenUE") Pure Power Program. (Id.) Similar to Rider VGP, the Pure Power Program is a voluntary non-commodity program that provides an opportunity for AmerenUE electric customers to purchase RECs. (Id., pp. 3-4.) Second, the AIUs conducted surveys to assess the level of Illinois residential customer interest in participating in a green program. (Id., p. 4.) Survey results indicate a substantial level of customer interest to pay an additional monthly fee to participate in a green program.[44] (Id.) Finally, the AmerenUE program, implemented in 2007, is similar to the AIUs proposed program, and in its first year, 4,000 participants purchased approximately 42,000 RECs.[45] (Id., p. 5.)

While Staff does not necessarily take issue with the concept of Rider VGP, Staff witness Ms. Ebrey asserts, in her direct testimony, that approval of Rider VGP would be premature, based on the plan the AIUs have thus far presented, which she believes lacks detail. (ICC Staff Ex. 1.0 (Ebrey Dir.), p. 36.) She asserts AIU should update its responses to Staff data requests outlining specific details of the plan, for Staff's review of those details. (Id., p. 37.) For the same reason, she argues it is also premature for the Commission to decide whether the VGP

[44] A total of nearly 2,200 customers were asked if they would be willing to pay more on their electric bill each month to help produce additional power from renewable resources and answered as follows: 22% responded "Yes"; 65% responded "No"; 13% responded "I Don't Know." (Ameren Ex. 14.0E (Mill Dir.), pp. 4-5.) Customers that responded "Yes" were asked how much extra they were willing to pay: about 33% agreed they would be willing to pay between $1 and $5 per month extra; 33% agreed they would be willing to pay between $5 and $10 extra per month; 14% agreed they would be willing to pay between $10 and $15 extra per month; 11% agreed they were willing to pay between $15 and $20 extra per month; 8% agreed they would be willing to pay $20 or more extra per month. (Id., p. 5.)

[45] The AmerenUE program is nationally recognized, including by the DOE, which named it the "most successful" New Green Power Program of the year. (Ameren Ex. 14.0E (Mill Dir.), p. 5.)

program would violate the IDC rules. (Id.) Ms. Ebrey is particularly critical of the lack of specific detail regarding process to account for program transactions and reconcile program revenues with RECs. (Ameren Ex. 39.0 Rev. (Mill Reb.), p. 5.) However, the AIUs understand that its accounting systems must be able to track the Rider VGP program residential billed charges, non-residential billed charges, receipt of payment from participants, REC purchases, RECs retired by virtue of program revenues, and how to account for customers not paying for three consecutive billing periods. (Id., p. 6.) The AMS Controller's group provided Mr. Mill with their recommended journal entries for the AIUs' Rider VGP program. (Id.) The proposed accounting entries are set forth in Ameren Exhibit 39.1, attached to Mr. Mill's rebuttal testimony and provided in a supplemental response to ICC Staff data request TEE 4.01 (TEE 4.01S). (Id.) The proposed accounting entries will treat program revenue in above the line revenue accounts. (Id.) Special monthly reports will track and report participant payment data. (Id.) The financial system will facilitate separate tracking and reporting of program billed revenue, participant payments, and program costs. (Id.) The entries also provide for the purchase of RECs. (Id.)

It is not clear how a lack of specific accounting entries can render Staff unable to make a recommendation regarding the program or on the IDC issue. (Ameren Ex. 39.0 Rev. (Mill Reb.), p. 6.) The Rider VGP "concept" is straightforward and not difficult to understand. (Id., p. 2.) Even so, Mr. Mill's rebuttal testimony provides further details regarding the program, set forth herein. (Id.) Moreover, as noted, Mr. Mill attached a draft Rider VGP to his direct testimony, as Ameren Exhibit 14.1. (Id., p. 3.) This draft describes the Purpose, Availability, Monthly Charges, Company Obligations and Terms and Conditions. (Id.)

Ms. Ebrey also recommends that, if the Commission adopts Rider VGP, the acquisition of RECs, as it relates to estimated participation levels, should first be addressed. (ICC Staff Ex. 15.0 (Ebrey Reb.), p. 26.) Specifically, she asserts the timing for the purchase of RECs is unclear from the information provided by the AIUs. (Id., p. 27.) Ms. Ebrey's concern is that, if the RECs are pre-purchased in anticipation of estimated participation levels, a procedure should be in place for the variance between anticipated and actual participation levels. (Id.) It appears Ms. Ebrey's confusion here stems from Ameren Exhibit 39.1, which illustrates accounting entries for the program costs and revenues. (Ameren Ex. 67.0 (Mill Sur.), p. 2.) The prepaid accounting scenario is set forth in the second set of entries under Section 1 of Ameren Exhibit 39.1, and Section 3 of that Exhibit illustrates when VGP participants pay for their program participation. (Id., p. 4.) Section 1 of that Exhibit shows when there is a purchase of RECs from a supplier funded by VGP revenues. (Id.) Moreover, Mr. Mill believes the AIUs' Rider VGP program will provide Staff and the Commission with adequate data and information on which to monitor the financial transactions under the program. (Id., p. 5.)

VI. COST OF SERVICE/REVENUE ALLOCATION

A. Overview

Relying in part on the Commission's guidance in Docket No. 07-0165, the AIUs focused their revenue allocation on mitigating the impact of the proposed rate increases on their gas and electric customers. As explained by Ameren witnesses Althoff, Normand, and Jones, the AIUs remain committed to developing rates that reflect cost causation and equitable cost recovery principles. In keeping with this consideration, the AIUs propose cost-based rates that result in a reasonable increase to each customer class. This proposal is both simple and fair.

The AIUs gas cost of service studies are largely uncontested with only one issue subject to dispute. The AIUs electric cost of service studies are subject to greater dispute. The AIUs have worked with the various parties in an effort to address whatever concerns each party has with the cost-based approach – each of these issues addressed below highlight the inadequacies with the arguments against the AIUs' approach. The methodologies employed by the AIUs are sound and appropriately applied to the cost of service data at hand. The Commission should adopt both the AIUs' revenue allocation proposal and the rate design it supports without modification.

B. Resolved Issues

1. <u>Gas/Electric</u>

2. <u>Electric</u>

3. <u>Gas</u>

a. *Weather Normalization*

The AIUs' proposed weather normalization analysis and adjustments are resolved issues. AIU witness Laderoute prepared a detailed weather normalization analysis and proposed to use an average of 10 years annual heating degree days ("HDD") based on historical data from the Champaign-Urbana weather station. (Ameren Ex. 21.0G Rev. (Laderoute Dir.), pp. 2, 6.) AIU witness Normand utilized this weather normalization analysis in his gas cost of service studies and rate design to adjust the historic test year so that it represented typical or normal circumstances from an HDD perspective. (Ameren Ex. 16.0G (Normand Dir.), pp. 3-4.) Staff witness Harden recommended that the Commission approve the AIUs' proposal to use a

10-year average of HDD for the purposes of weather normalizing billing determinants in these proceedings. (ICC Staff Ex. 9.0 (Harden Dir.), pp. 6-7.)

No other party commented on the AIUs' weather normalization approach. As such, there appears to be general agreement that the Commission should adopt the weather normalization approach presented by AIU witnesses Laderoute and Normand.

b. *Billing Determinants*

The billing determinants adjustments used in the gas cost of service studies and ratemaking is a resolved issue. The AIUs proposed to adjust the existing non-residential customer billing determinants for GDS-2, GDS-3, and GDS-4 for AmerenCILCO and AmerenCIPS, to allow for the change in AmerenCILCO's and AmerenCIPS's rate class availability provisions to match the AmerenIP class definitions.[46] (Ameren Ex. 16.0G (Normand Dir.), p. 5.) These adjustments anticipate the changes due to customer reclassification within GDS-2, GDS-3, and GDS-4. (Ameren Ex.17.0G Rev. (Millburg Dir.), p. 9.) Staff witness Harden agreed with the AIUs' proposed adjustment to the billing determinants based on the reclassification of GDS-2, GDS-3, and GDS-4. (ICC Staff Ex. 9.0 (Harden Dir.), pp. 8-9.) Ms. Harden testified that "[t]he change to test year billing determinants is appropriate based on Ameren's proposal for reclassification" because "[t]he adjustments will realign proposed revenues so that the revenue requirement that is approved in the final order of these dockets will more accurately reflect test period sales." (Id., p. 9, line 172) No other party commented on the AIUs' billing determinants adjustments.

[46] See Section VII.C.1.a., below, for a discussion of the proposed change in GDS-2, GDS-3, and GDS-4 availability provisions.

There is general agreement that the Commission should adopt the AIUs' billing determinants adjustments. While the billing determinant adjustments are not contested, the underlying change to the AmerenCILCO and AmerenCIPS rate class definition is a contested issue as described in Section VII.C.1.a. The Commission should approve the AIUs' proposed changes to the GDS-2, GDS-3, and GDS-4 rate class definition for AmerenCILCO and AmerenCIPS along with the associated billing determinant adjustments. If, however, the Commission approves rate class definitions different from those proposed by the AIUs, then the AIUs will need to readjust the billing determinants in accordance with the approved rate class definitions.

c. *Rate Classes*

The AIUs' proposal to retain most of the existing rate classes is a resolved issue. The AIUs propose to maintain six general rate classes for each of the AIUs: (1) GDS-1 Residential; (2) GDS-2 Small General Service; (3) GDS-3 Intermediate General Services; (4) GDS-4 Large General Service; (5) GDS-5 Seasonal Gas Delivery Service; (6) GDS-7 Special Contract Gas Delivery Service. Other than elimination of AmerenCILCO's GDS-6 rate class, the AIUs did not propose changes to these general rate classes. (See, e.g., Ameren Ex. 17.0G Rev. (Millburg Dir.) pp. 3-6.) Staff witness Harden approved the proposed rates and rate design based on these six rate classes. (See, e.g., ICC Staff Ex. 9.0 (Harden Dir.), pp. 18, 43.)

The AIUs have proposed only one change to their general rate classifications. In particular, AmerenCILCO is the only one of the AIUs that currently offers Large Volume Gas Delivery Service under rate class GDS-6. The AIUs propose to eliminate AmerenCILCO's GDS-6 as a stand-alone rate and to incorporate additional provisions within AmerenCILCO's GDS-4 tariff to address the large usage customers. (Ameren Ex. 17.0G Rev., p. 21.) Staff witness Harden recommends approval of the AIUs' proposal to eliminate AmerenCILCO's GDS-6 on a stand-alone basis. (ICC Staff Ex. 9.0, pp. 36-37.)

No other party commented on the AIUs' rate classification approach. As such, there appears to be general agreement that the Commission should adopt the rate classification approach presented by AIU witnesses Millburg and Normand.

C. Contested Issues

1. Electric

As explained by the AIUs' witnesses Althoff and Jones, the AIUs remain committed to developing rates that reflect equitable cost recovery principles. In keeping with that consideration, the AIUs propose cost-based rates that result in a reasonable increase to each customer class. While the AIUs, Staff, and IIEC have all weighed in on this issue, only the AIUs have performed an independent Cost of Service Study[47] based on a proprietary model in preparation for this rate case – the remaining parties all use some derivation of the AIUs' proposal. (See, e.g., IIEC Ex. 4.0, p. 8; ICC Staff Ex. 7.0, p. 3.)

The AIUs' cost-based rate proposal is both simple and fair. The AIUs have worked with the various parties in an effort to address whatever concerns each party has with respect to the their proposals. The issues addressed below highlight the inadequacies of the arguments against the AIUs' approach. The AIUs employed sound methodologies and appropriately

[47] The phrases cost of service study, embedded cost of service study, and related acronyms such as ECOSS or ECOS-study all refer to the same analytical ratemaking process. It should be noted that the term "E-cost" was recorded several times in the transcript as a result of the court reporters' understanding of the phonetic pronunciation of the acronym ECOSS. (See, e.g., Tr. 708-709.)

applied those methodologies to the cost of service data at hand. For the following reasons, the Commission should adopt the AIUs' revenue allocation proposal and ultimately, the rate design it supports.

a. *AIUs' Cost of Service Studies*

The AIUs' witnesses presented the electric embedded cost of service studies that they performed for the electric retail jurisdictional delivery services using a test year of 12 months, ending on December 31, 2008. (Ameren Ex. 17.0E, p. 2.) As Staff and the IIEC's cost of service witnesses agreed at hearing, the purpose of a cost of service study is to support the development of cost-based rates. (Tr. 150, 728.) As discussed more thoroughly in the Rate Design section below, no party to this proceeding has recommended rates that are in strict accordance with the cost of service study results. Rather, the AIUs, Staff, and IIEC – the three parties offering cost of service study and rate design testimony – applied rate mitigation considerations to cost of service indicators to develop rates. (See Ameren Ex. 55.1.)

As noted above, the AIUs are the only parties to offer a cost of service study based upon its own model. Staff and the IIEC –the only other parties that offer ECOSS analysis –use variants of the AIUs' model to develop their recommendations. (See IIEC Ex. 4.0, p. 8; ICC Staff Ex. 7.0, p. 3.) Those variations result from disagreements regarding the appropriateness of allocators, allocation methodologies, and the manner in which distribution tax liabilities should be allocated among customer classes.

The class cost of service study presented by the AIUs in these cases are the result of the process of allocating and assigning the various cost elements of providing electric delivery service to these various customer classes in a way that best reflects the manner in which such costs are incurred in providing delivery service. (Ameren Ex. 17.0E, p. 3.) The results of the class cost of service study are often referred to as the "class revenue requirements," which represent for each rate class its equitable share of the total annual cost of providing electric delivery service. (Id.)

There are three separate steps in the ECOSS: functionalization, classification, and allocation. (Id., p. 4.) Functionalization is the assignment of rate base items and operating expenses to cost functions. (Id.) Classification is the assignment of the functionalized costs to categories of cost causation. (Id.) Allocations were used to assign the classified costs to the various classes of service. (Id.)

When preparing the ECOSS, the AIUs classified each rate base and expense item in the electric delivery revenue requirement on the basis of cost causation to demand-subtransmission, demand-distribution, or customer. (Id.) Demand-subtransmission and demand-distribution costs are those investments and expense items that are incurred to meet system peak load requirements and local maximum demands, respectively. (Id.) Customer-related costs are those investments and expense items which are incurred to service customers and which do not vary with changes in consumption, such as the cost of the customer's meter and service drop. (Id., p. 5.)

In the development of Distribution Plant in the ECOSS model, the capital asset costs are segregated according to voltage level. Demand-related costs were allocated to customer classes based on the contribution of each customer class to the system's non-coincident peak ("NCP") demand based on the costs at the various voltage levels. (Id.)

The AIUs methodologies were approved by the Commission in its Final Order in Docket Nos. 06-0070 (cons.). (Id.) Some allocation factors were modified to more appropriately follow current operations and customer demand. (Id.) Ms. Althoff specifically explains her allocation methodologies in detail in her direct testimony. (See Ameren Ex. 17.0, pp. 6-13.)

After reviewing the testimony, the AIUs identified one necessary change to the ECOSS. Specifically, a review of the study has revealed that the allocator used to determine how the FERC Account 362 is allocated to customers was initially incorrect. (Tr. 570.) At hearing, AIU witness Althoff agreed to an allocation recommendation offered by the IIEC to the change. (Id.) The AIUs now agree that the DDSUBTR allocator should be used to allocate the costs of the 362 FERC account. (Id., p. 571.) The DDSUBTR allocator is more appropriate, because it selectively allocates this cost to customers with delivery voltage is less than 100+kv. (See id., pp. 570-571; IIEC Ex. 4.0, pp. 9-11.) Additionally, the change to the DDSUBTR allocator is appropriate because it more closely matches the function of the substations – lowering the supply voltage down to delivery voltage. (Tr. 606.) Adopting the DDSUBTR allocator does not materially alter the results of the AIUs' ultimate cost of service study recommendations.

Adopting the DDSUBTR results in the reallocation of approximately $25 million to the DS-4 100+ kV customer subclass, out of $4.3 billion in total AIU allocable gross distribution plant. (See IIEC Ex. 4.0, pp. 9-11.) The $27 million value cited by IIEC witness Mr. Stowe is a gross number before depreciation is applied, and ultimately translates into a revenue requirement reallocation totaling approximately $4 million (calculated as rate of return multiplied by cumulative depreciation, less allocation depreciation, plus allocation depreciation expense[48]) of associated revenue requirement to the DS-4 100+ kV customer subclass. The practical effect, the revenue requirement reallocation will not reach $4 million if the AIUs receive approval of a revenue requirement lower than request.

As noted above, the ECOSS results were used for the basis of rates from which mitigation rate design considerations are applied by all parties. The AIUs have already applied a mitigation methodology to all customer classes that has allocated more than $4 million away from the DS-4 100+ KV customers to other customer classes. (See Ameren Ex. 55.0 Rev., pp. 2-5; Ameren Ex. 55.1.) As a result, accepting the DDSUBTR allocator has no consequence for the AIUs' filed position. Staff applies a mitigation strategy that has similar effects. (Staff Ex. 7.0, p. 19)

The IIEC also offered a rate mitigation plan, but specifically re-ran the cost of service study to show the effects of the use of the allocator DDSUBTR. (See IIEC Ex. 4.0, pp. 3-14.; IIEC Ex. 1.0, pp. 29-33.) The IIEC presumably took that matter into consideration in its rate design recommendation. (Id.)

Assigning specific costs to broad rate classifications is a task not free of subjective consideration, and requires some degree of generalized application and educated assumption. Regardless, the AIUs are the stewards of the cost of service study they maintain. They are always willing to redress legitimate concerns regarding their study, as well as any similar models offered by the Staff and customers. The AIUs are confident that their study presents a highly accurate allocation of cost causation. The AIUs have addressed, and will continue to

[48] See Appendix G hereto for the complete calculation with citations to the record.

address, stakeholder recommendations that could enable the AIUs to allocate costs more precisely in future rate cases.

In the instant case, the AIUs' proposal presents the most pertinent and accurate cost indicators in support of the rate design proposal. The AIUs have prepared a competent study, sponsored by a witness with many years of rate design and cost of service experience in Illinois. (*See* Ameren Ex. 17.0E, Appendix.) The AIUs' proprietary ECOSS model and results were thoroughly vetted by both Staff and the IIEC during the course of the proceeding. It was even utilized by both of those parties as a starting point for counter proposals. (See, e.g., id.)

Accordingly, the Commission should accept the AIUs' embedded cost of service proposal.

b. *Allocation of Costs to Customers Receiving Service at Voltages 100+ Kv*

Customers receiving service at 100+ KV in DS-4 essentially take service at a transmission voltage. (See Tr. 710.) Unlike the AIUs' other customer classes , the DS-4 customer class is populate by a relatively few customers with large electric demand. (Tr. 620-21; Ameren Ex. 41.0 (Althoff Reb.) pp. 10-11.) Additionally, these DS-4 customers often have multiple service points. (Id.) They can own or rent substations or transformers. They can utilize AIU substations or transformers, or some combination of the above. (Id.)

The IIEC acknowledges that 100+ KV DS-4 customers should pay something for their service. The IIEC, however, disputes the AIUs' allocation of costs to the customers that operate at the highest voltage level – 100 kV or higher. (See Tr. 718-19.) The IIEC specifically contends that customers taking service at a voltage above 100 kV do not receive any benefit from the portions of the distribution system that operate below that the 100 kV voltage level. (IIEC Ex.

8.0, p. 10.) However, many customers supplied at 100+ kV do use transformers and substations owned by the AIUs, and should not be able to bypass delivery service rate responsibility associated with use of the system. (See Ameren Ex. 56.0 Rev., p. 12; Tr. 718.)

The IIEC's argument only considers the "Supply Voltage" of these customers. (Ameren Ex. 41.0, p. 10.) The IIEC's allocations do not appropriately portray the changes in the class demand studies between the current and prior delivery services cases. (Id., p. 7.) the allocation factors used in the current case are based on a combination of supply and delivery voltage. (See Ameren Ex. 41.1.) Based on the AIUs' voltage definitions, customers can be supplied via substation feeder at one voltage level, but ultimately delivered at a lower voltage level. (Ameren Ex. 41.0, p. 7.) While it is true that the previous case's allocation factors were based on supply voltage alone, the current case's allocations are a better representation of cost causation due to the recognition of delivery voltage. (Id., p. 8; Ameren Ex. 41.1.)

The AIUs' Transformation Charge provides additional support for the proposition that customers can be supplied at one voltage but delivered at a lower voltage. (Id., p. 11.) More particularly, a customer will be billed a Transformation Charge to compensate the AIUs for providing transformation of voltage from the customer's Supply Voltage to the Delivery Voltage used by the customer. (Id.) Costs are properly allocated to customers supplied at 100 kV and above, but delivered at lower voltages to match how the AIUs' assets are being used by customers. (Id.)

Further, if customers use their own transformers, those customers' demands are not included in the lower delivery voltage category. (Id.) The same effect holds true for customers who rent transformers. (Id.) Those Delivery Voltage demands for customers who rent transformers are included and costs are appropriately allocated but revenues from rentals are included as an offset to the revenue requirement. (Id.)

Additionally, this class represents only a small number of the AIUs' customers and these few customers accept delivery service in differing configurations. There is, for instance, one customer that does not require transformation because that service provided is a switchyard. There are three customers that own their transformers. (Ameren Ex. 56.0 Rev., p. 13.) Of the remaining customers, ten either rent or are charged for transformation service from the AIUs on their entire load and two customers receive transformation service on a portion of their load. (Id.) All totaled, five customers do not take transformation service from the AIUs, and 12 customers do take transformation service from the AIUs. (Id., p. 14.)

As explained above, the AIUs have changed their position with respect to the allocator used to determine how FERC Account 362 is distributed for this group. The Commission should accept the AIUs' general methodology, as modified. First, as noted above, an ECOSS will not always perfectly match costs, expenses, and miscellaneous revenues perfectly, since it allocates to all customer classes. (Id..) As Mr. Stowe agreed, the purpose of an ECOSS study is to allocate costs to classes of customers. (See Tr. 728 (emphasis added).) Further, Mr. Stowe agreed that up until the present, ECOSS have not been used to develop customer rates for individual customers. (Id., p. 729.) With these acknowledgements noted, it is inevitable that there will always be outliers in an ECOSS as uniform rates by class are produced, and outliers in customer classes with relatively few customers will be difficult to address. (Ameren Ex. 56.0 Rev., p. 16.) While the AIUs can refine their methodologies to be as accurate as possible, it is important to continue the practice of allocating costs at a class level rather than focusing on the particulars of individual customer cost causation.

For the above stated reasons stated, the Commission should adopt the AIUs' general approach for allocated costs to the 100+ kV class of customers should.

c. *Allocation of Cost of Primary Distribution Lines and Substations*

The AIUs propose that the allocation of substation and primary line costs to the customer rate classes be allocated based on non-coincident peak ("NCP") demand. IIEC concurs with the AIUs that the NCP methodology is the appropriate method of conducting allocations. (IIEC Ex. 8.0 (Stowe Reb.) p. 19.) Staff, however, recommends that substation and primary line costs be allocated on a basis of coincident peak ("CP") rather than NCP. (ICC Staff Ex. 7.0, p. 5.) The CP method allocates costs based on the demands of individual customers at the time of system peak, while the NCP method allocates costs based on the demands of individual customers at the time of peak for the class. (Ameren Ex. 56.0 Rev., p. 2.) The Commission has approved the application of the NCP methodology to allocation the distribution plant costs in the AIUs' prior delivery services rate orders. (Ameren Ex. 41.0, p. 2.) Additionally, the use of NCP more appropriately allocates costs to customers that cause the costs to arise because, on-balance, NCP demands more closely match the demands placed on local substation and primary line facilities. (Id.)

Staff contends that CP represents the collective demands of multiple rate classes and that facilities are built to serve demands based on locality which most likely serves customers in various rate classes. (ICC Staff Ex. 7.0, p. 5.) Staff is correct that the AIUs' facilities are built to serve demands based on locality and that geographical locations do encompass customers in multiple rate classes. Staff, however, does consider the fact that customers within these geographical locations can peak at various times throughout the year. (Ameren Ex. 41.0, p. 3.)

Staff's focus appears to be on the "multiple rate classes" element of CP demand, ignoring the fact that the CP demand is always less than the sum of the localized demands placed on distribution facilities. (Id.) The CP demand includes the load diversity of the entire delivery system. (Id.) Local facilities such as substations and primary lines are not built and sized with this level of diversity in mind. (Id.) Instead, distribution system planners look at the expected peak of customers connected to the facilities, whether they occur in summer, fall, winter, or spring. (Id.) This is based on the fact that the collective peaks on individual systems are greater than the CP. (Id., p. 4.) The NCP demand more closely matches the load diversity on these more localized system. (Id.)

The use of CP demand would not be beneficial to many of the AIUs' customers. The use of CP would increase costs to the DS-1, DS-3, and DS-4 rate classes but would lower costs to the DS-2 and DS-5 classes for AmerenIP. (Ameren Ex. 41.0, p. 4.) For Ameren CIPS, the DS-3 and DS-5 classes would be allocated lower costs under the CP allocation; however, the DS-1, DS-2, and DS-4 customers' costs would increase. (Id.) The affects for AmerenCILCO are that the DS-1 and DS-5 rate classes receive less costs utilizing CP while DS-2, DS-3, and DS-4's costs would be higher. (Id.)

Staff further contends that lighting customers should not bear any costs with substations or primary lines, since they are peak during off-peak, evening hours, and states that peak lighting loads should play a lesser role in determining the size of primary distribution lines and substations. (ICC Staff Ex. 7.0, p. 8.) Under Staff's application of CP, lighting customers would be allocated zero costs for substations and primary lines. (Id.) Lighting customers, however, use primary lines and substations and should be allocated at least some costs for the use of these assets. (Ameren Ex. 56.0 Rev., p. 4.) To allocate zero substation and primary line costs to the lighting class is flatly incorrect, given that they use these assets. (Id.)

Staff also advocates the use of a different allocation factor known as 12 CP. (ICC Staff Ex. 21.0 (Lazare Reb.) p. 8.) The 12 CP method supports the basic premise that utilities install facilities to maintain a constant level of reliability throughout the year. (Ameren Ex. 56.0 Rev. (Althoff Sur.) p. 5.) However, the 12 CP method produces results not substantially different than the NCP method, which contradicts Staff's point to use a single CP for the allocation of these two assets. (Id.) For example, in the lighting class, the NCP method allocates 1.7%, 0.7%, and 1.3% to AmerenIP, AmerenCILCO, and AmerenCIPS, respectively, for primary lines and substations, while the 12 CP method allocates 1.2%, 0.5%, and 0.6% to each respective AIU. (Id.) On the other hand, the use of CP allocates zero to the lighting rate class for primary lines and substations. (Id.) Thus, Staff's two propositions are almost wholly contradictory.

Additionally, the use of NCP does not "punish" non-weather-sensitive customers, as Staff contends. Instead, it appropriately allocates the cost of facilities to match how the facilities were designed, built, and sized. (Id., p. 7.) CP, on the other hand, is a detriment to these rate classes, as evidenced by the cost of service study. (Id.) Accordingly, allocating substations and primary lines based on CP would be improper because using that would fail to appropriately align costs with the cost causers for which the systems are designed and constructed. (Ameren Ex. 41.0, p. 6.) The use of NCP provides the most accurate methodology for allocating distribution assets to ensure that no customer rate class subsidization occurs. (Id.)

d. *Allocation of Electric Distribution Tax/Public Utilities Revenue Act Tax*

The AIUs propose that the electric distribution tax should be allocated and collected based on kWh sales. IIEC opposes that proposition and, instead, contends that the tax should be allocated on a demand basis, using the manner in which the tax was assessed and collected before 1998. (IIEC Ex. 5.0, p. 7.) Staff does not support IIEC's proposition. (ICC Staff Ex. 21.0, pp. 2-3.)

IIEC's approach is inappropriate, because the structure of the tax is such that as a utility delivers more or less energy, the amount of tax will increase or decrease, all other things constant. (Ameren Ex. 55.0 (Rev.), p. 16.) That means that plant is not a determining factor of the tax amount, but rather that the amount of kWh delivered is determinative. (Id.)

Further, the difference between the AIUs today and the AIUs in 1997 IS that in 1997 each of the AIUs owned its own generation facilities that were part of the utility plant in service and provided fully bundled electric service. (Id.) Allocating and assigning the cost based on kWh is far superior to allocating the tax based on costs that no longer include generation plant. The AIUs proposal to collect the electric distribution tax based on kWh sales is consistent with the legislative intent of the law. See 35 ILCS § 620/1a. Accordingly, the Commission should adopt the AIUs' kWh-based proposal.

e. *NCP Class Demands*

The AIUs addressed this issue above in Section VI.C.1.e., entitled "Allocation of Costs to Customers Receiving Service at Voltages 100+ kV." The AIUs, however, reserve the right to respond to issues and arguments other parties raise with respect to this sub-issue.

f. *Other*

During the course of the hearing, the IIEC raised the notion of re-running the class cost of service study. (See Tr. 580-81.) This would not be a useful exercise and would not benefit the Commission's consideration of the issues in this case. Utilities do not typically completely re-run an ECOSS during in a rate case. (Tr. 616.) Unnecessarily expanding the evidentiary phase of the case only prolongs and complicates an already arduous process. It is unclear what re-running the ECOSS would accomplish.

The Commission must remember that the ECOSS is merely a foundational step that is only conducted to provide support for AIUs' ultimate rate design recommendations. Absent the rate design considerations it is intended to support, an ECOSS update would not provide any additional analytical value. The revenue requirement values entered into the ECOSS at the beginning of the case will change as a result of the Commission's decision in these cases. Conforming the rate design to the final revenue requirement, both at aggregate and class level, should not be addressed by reopening the evidentiary record. Instead, the final revenue requirement is more properly addressed by reference to witness testimony specific to that very subject. Here, witnesses Mr. Jones and Mr. Lazare have offered testimony with regard to the methodology utilized to adjust proposed rates to the final revenue requirement. (*See* Staff Ex. 7.0, p. 41; Ameren Ex. 40.0, pp. 15-17.) As it stands, the record provides ample evidence for the

Commission to redress the contested issues in this matter. Thus, re-running the ECOSS is unnecessary.

2. Gas

a. *Account 904*

AIU witness Normand addressed net write-offs recorded in the Uncollectible Expenses, Account 904, as part of his gas cost of service analysis. (See, e.g., Ameren Ex. 16.4G, p. 37; Ameren Ex. 16.5G, p. 37.) Staff witness Harden identified to Mr. Normand that the net write-offs recorded in Account 904 had been the allocated the same percentage for each class in each cost study. (Ameren Ex. 27.0 (Normand Reb.), p. 2.) Mr. Normand corrected this oversight in his rebuttal testimony and noted that the AmerenIP allocation was correct, but that his initial Account 904 allocations were incorrect for AmerenCIPS and AmerenCILCO. (Id.) Mr. Normand reran his cost of service studies to quantify the impact of the oversight and provided updated cost of service studies for AmerenCIPS and AmerenCILCO that corrected for the Account 904 allocation oversight. (Id.; see also Ameren Exs. 27.1 and 27.2.) Mr. Normand testified that, while the class impacts of the updated cost of service studies on AmerenCIPS and AmerenCILCO were de minimis, the results of the updated cost of service studies should be factored into the final rate design approved by the Commission. (Ameren Ex. 27.0, p. 3.)

Ms. Harden's rebuttal testimony did not address the cost of service study adjustments proposed by Mr. Normand to address the Account 904 allocation corrections. The AIUs, therefore, believe that Ms. Harden has accepted Mr. Normand's corrections. Although this section is contained in the Contested Cost of Service section of this brief, the AIUs believe this is a resolved issue.

b. *Storage Cost Allocations between Sales and Transportation Customers*

The AIUs incur storage costs associated with both on-system storage facilities and off-system storage facilities. On-system underground storage facility costs are recovered in the base rates.[49] (Ameren Ex. 57.0 (Normand Sur.), pp. 5-6.) In his gas cost of service studies, AIU witness Normand allocated costs to both sales and transportation customers.[50] Mr. Normand and the AIUs propose to allocate on-system underground storage plant facility costs based on the transportation customers' actual peak day usage during the historic test year. (Ameren Ex. 27.3.) The AIUs segregate these on-system storage costs "into a portion that supports the delivery function applicable to all sales customers and a separate portion assignable to transportation customers based on their ability to withdraw gas from their transportation banks on a peak day." (Ameren Exhibit 16.0G (Normand Dir.), p. 10, lines 188-91.) Staff, on the other hand, proposes to allocate these costs based on the transportation customers' Daily Confirmed Nomination ("DCN") on the same day. (ICC Staff Ex. 27.0R (Sackett Reb.), p. 38.)

The following table shows the percentage of on-system storage costs allocated to transportation customers under the AIUs and Staff proposals. The remaining on-system storage costs would be allocated to the sales customers. The AIUs and Staff disagree not only

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[49] Off-system underground storage facility costs, however, are recovered only from sales customers as part of a different recovery mechanism. (Id.) Off-system storage costs are not part of these rate cases because the AIUs. (Id.)

[50] The AIUs provide two general categories of service to their commercial customers. The customers can either receive sales service (*i.e.,* the AIUs sell and deliver gas to the customer) or transportation service (*i.e.,* the AIUs deliver to the customer gas that the customer purchased from a third party).

on the resulting allocation percentages, but also on the method for developing those percentages.

Proposed Allocation of On-System Storage Costs to Transportation Customers		
	AIU's Allocation Based on Actual Planned Peak Day Usage (*See, e.g.,* Ameren Exhibit Ex. 27.3)	Staff's Allocation Based on DCN (ICC Staff Exhibit Ex. 27.0R, p. 38.)
AmerenCIPS	18.00%	14.02%
AmerenCILCO	5.53%	3.96%
AmerenIP	5.21%	3.80%
Total	6.19%	4.55%

Transportation customers have a limited ability to withdraw gas from their transportation banks on a peak day. The AIUs base the on-system storage allocation on the relative size of the Transportation customers' withdrawal ability. On a Critical Day, daily balanced customers can call on their storage bank for up to 20% of their DCN and monthly balanced transportation customers can call on the storage bank for up to 50% of their DCN. (AmerenCIPS's Rider T - Gas Service Schedule Ill. C.C. No. 20, 2nd Revised Sheet Nos. 25.005-25.006; AmerenIP's Rider T - Gas Service Schedule Ill. C.C. No. 37, 1st Revised Sheet Nos. 25.005-25.006; AmerenCILCO's Rider T - Gas Service Schedule Ill. C.C. No. 19, 1st Revised Sheet Nos. 25.005-25.006.) The AIUs must operationally plan to serve transportation customer banks on a Critical Day, but the AIUs do not know what the transportation customers will nominate on any given day in the future. From a planning perspective, the AIUs assume that transportation customers as an aggregate will call on the storage bank for 20% of their usage on a future peak day. (See Ameren Ex. 27.0 (Normand Reb.), pp. 7-8.) The AIUs, therefore, determined the amount of on-system storage capacity planned to serve 20% of the transportation customers' peak day usage and allocated a portion of the on-system storage capacity costs based on the ratio of the transportation customers' peak day capacity usage to the total on-system storage capacity.[51] (See id., pp. 4-5.)

The AIU's proposed allocation of storage plant facility costs to transportation customers is based on the transportation customers' actual peak day usage during the 2008 test year. (Id.) The following table shows the how the AIUs determined the allocation percentage for AmerenCIPS. (See, e.g., Ameren Ex. 27.3.) In this example, AmerenCIPS's 2008 peak day usage was 60,436 therms. (Id.) Excluding the usage associated with special contracts and GDS-7 customers results in 34,204 therms of relevant peak day usage.[52] (Id.) Applying the AIUs' actual 20% planning assumption to the 34,204 therms of relevant transportation customer peak day usage results in an expected bank withdrawal of 6,841 therms. (Id.) AmerenCIPS has 38,000 therms of on system storage capacity. (Id.) The 6,841 therms of expected bank withdrawal rights represents 18.00% of the 38,000 therms of on-system storage capacity available to the transportation customers. (Id.)

	Calculation of the Transportation Customers' Allocation of On-System Storage Facility Costs	AmerenCIPS
(a)	Transportation customers' relevant 2008 peak day usage	30,204 therms

[51] Staff witness Sackett utilized the same 20% factor in his on-system storage cost allocation methodology – he just applied it to the transportation customers' aggregate DCN rather than the transportation customers' aggregate peak day usage. (See, e.g., ICC Staff Ex. 27.0R (Sackett Reb.), p. 38, Figure 5.)

[52] The allocations to these customers are addressed separately. Therefore, their relative usage is not material to this ratio. The exclusion of these customers' peak day usage from this calculation is not contested.

(b)	Planning Factor	20%
(c)	Bank Withdrawal Rights – *i.e.,* (a) times (b)	6,841 therms
(d)	Total On-System Storage Capacity	38,000 therms
(e)	Allocation Percentage – *i.e.,* (c) divided by (d)	18.00%

The AIUs therefore allocated 18.00% of AmerenCIPS's on-system storage costs to the AmerenCIPS transportation customers. The remaining 82.00% of the on-system storage costs was allocated to sales customers. Following the same method for AmerenCILCO results in the allocation of 5.53% of AmerenCILCO's on-system storage costs to the AmerenCILCO transportation customers. (Id.) Likewise, applying that calculation to AmerenIP results in the allocation of 5.21% of AmerenIP's on-system storage costs to the AmerenIP transportation customers. (Id.)

The AIUs, therefore, base their proposed rates on the following allocations of on-system storage costs to the transportation customers: (a) AmerenCIPS – 18.00%; (b) AmerenCILCO – 5.53%; and (c) AmerenIP – 5.21%. These percentages are based on the transportation customers' ability to rely on these facilities to serve their peak day usage with bank withdrawals. (Ameren Ex. 16.0G, p. 10.)

Staff takes issue with the AIUs' methodology. Rather than allocate costs based, in essence, on the AIUs' planned deliverability to customers (*i.e.,* the amount of capacity that the AIUs actually acquired and accounted for in their peak day planning for these customers), Staff witness Sackett recommends that the AIUs allocate on-system storage costs based on 20% of the transportation customers DCN on the 2008 test year peak day. (ICC Staff Ex. 27.0R., pp. 37-

39.) The DCN for that peak day represents the amount of gas that the transportation customers intended to deliver for that peak day. (See, e.g., Tr. 371-72 ("Q: And how does [DCN] relate to deliveries? A: You would hope that deliveries would match the nominations. They may. They may not, but you would hope they would.").)

Staff claims that it is more appropriate to allocate the on-system storage cost based on a percentage of DCN because the AIUs' tariffs allow transportation customers to call their bank capacity for up to 20% of their DCN. (ICC Staff Ex. 27.0R, p. 37.) A thorough review of Mr. Sackett's proposal shows that it is fatally flawed.

First, as described above, the AIUs based their peak day facility plan on the assumption that transportation customers will call on storage banking for 20% of their expected usage. (See Ameren Ex. 27.0 Rev., p. 8, lines 154-55 ("Mr. Dothage also mentioned that, for planning purposes, he also assumes a 20% requirement for transportation customers."); Ameren Ex. 57.0, p. 8, lines 82-84 ("The only equitable approach was to use the transportation customers' peak day usage levels as a more appropriate load level reflective of maximum or peak day design day for which the AIU's resources are planned.").) The AIUs' approach of using actual peak day usage mirrors more closely a true and reasonable design day level requirement from which costs can be reasonably assigned to transportation customers. (Id., p. 6.) The approach of using only the DCN, as proposed by Mr. Sackett, understates the cost responsibility to transportation customers with the remaining cost responsibility being absorbed by sales customers. (Id.)

Second, the transportation customers' DCN is discretionary and not predictable. A transportation customer can nominate as little as zero therms for a peak day, as much as 100%

of MDCQ for daily-balanced customers, or 200% of MDCQ for monthly balanced customers. (AmerenCIPS's Rider T - Gas Service Schedule Ill. C.C. No. 20, 2nd Revised Sheet Nos. 25.008; AmerenIP's Rider T - Gas Service Schedule Ill. C.C. No. 37, 1st Revised Sheet Nos. 25.008; AmerenCILCO's Rider T - Gas Service Schedule Ill. C.C. No. 19, 1st Revised Sheet Nos. 25.008.) It is up to each transportation customer to decide how much gas to nominate on a day. (Tr. 879.) The customer may not be able call on storage bank if, for example, the customer did not have a positive bank balance. Moreover, the customer may choose not to call on their storage bank for a commercial reason. Alternatively, transportation customers can call on the transportation bank for as much as 20% to 40% of their MDCQ if they nominated the maximum amount available under the tariff. The AIUs do not know what a transportation customer individually, or transportation customers in aggregate, will nominate for any given day. Due to the discretionary nature of the DCN, the AIUs do not plan their resources assuming 20% of historic DCN.

Mr. Sackett testifies that basing the allocation on 20% of peak day usage rather than 20% of DCN over-allocates costs to transportation customers. (ICC Staff Ex. 27.0R, p. 37.) Mr. Sackett gets it wrong. While DCN levels are a fair starting or reference point, the transportation customers' DCNs are significantly lower than the transportation customers' actual peak day usage. (Ameren Ex. 57.0, p. 3.) Basing the on-peak storage allocations on transportation customers' DCNs would materially understate the storage cost responsibility to transportation customers. (Id.) Instead, when allocating the storage costs, the AIUs should consider not only the starting DCN, but also the actual peak day use of transportation customers. (Id.)

The Commission should permit the AIUs to allocate on-system storage costs based on the transportation customers' peak day usage that would capture the initial DCN levels, plus rather large additional levels of use. (Id.)

c. *Other*

VII. RATE DESIGN/TARIFF TERMS AND CONDITIONS

A. Overview

In prior rate cases, CILCO, CIPS, and IP made great steps towards greater uniformity among the AIUs' tariffs. The Commission has encouraged and approved these steps towards tariff uniformity in the past for CILCO, CIPS, and IP among DS tariffs and gas tariffs. Continuing to do so in this proceeding makes sense.

One of the primary roles of the AIUs is to maintain system integrity through up-to-date facilities, tariffs, and the AIUs business practices. Fulfilling this role will go far to ensure the continuous delivery of natural gas and electric power to all customers on the system. In addition to addressing the Commission's uniformity directive, the changes addressed below benefit the AIUs' operating practices and rate administration, as well as the customers. As follows, the Commission should adopt the AIUs' proposals to update, standardize, and improve their abilities to serve their customers.

B. Resolved Issues

1. Gas and Electric

a. *Combining Customer and Meter Charges*

The AIUs have withdrawn their proposal to combine customer and meter charges into a single "Fixed Monthly Charge." As such, this issue has been resolved.

The AIUs initially proposed to combine the electric utilities' Customer Charge and Meter Charge into a new "Fixed Monthly Charge" that would be shown on the customer bills. (Ameren Ex. 16.0E 2d Rev. (Jones Dir.), p. 17.) Currently, the Meter Charge is identified separate from the Customer Charge because customers have the option of receiving metering services from a Meter Service Provider ("MSP") other than the AIUs. (Id.) There are no MSPs operating within the AIUs' service areas, however, and no MSPs offered service in the AIUs service areas during 10 years that the program has been in effect. (Id.) However, Staff witness Lazare objects to the AIUs proposal to combine the Customer and Meter charges on the grounds that the proposal would impede efforts in the future to build the market for unbundled metering. (ICC Staff Ex. 7.0 (Lazare Dir.), p. 23.) In the interest of narrowing issues in this proceeding, the AIUs have agreed not to pursue their proposal to combine the Customer and Meter Charges for bill presentation purposes on customer bills. (Ameren Ex. 40.0 2d Rev. (Jones Reb.), p. 3.) As a result, this issue has been resolved.

b. *Customer Charge Label*

The AIUs initially proposed to rename the "Customer Charge" to "Fixed Monthly Charge" on their gas customer bills. (Ameren Ex. 17.0G Rev. (Millburg Dir.), p. 12.) However, Staff witness Boggs opposed that proposal. (ICC Staff Ex. 10.0 (Boggs Dir.), pp. 7-9.) In the interest of narrowing issues in this proceeding, the AIUs agreed not to pursue their proposal to rename the Customer Charge to Fixed Monthly Charge on gas customer bills. (Ameren Ex. 48.0 Rev., (Millburg Reb.), p. 2.) As a result, this issue has been resolved.

c. *Uncollectibles Factors – Riders EUA and GUA*

Pursuant to section 2 of the stipulation in Docket No. 09-0399, the AIUs and Staff have agreed:

> [T]he uncollectible amounts included in rates for the periods on and after the date new rates take effect (pursuant to 09-0306 et al (Cons.)) shall be determined for each relevant customer rate class as defined in Rider EUA as follows:
>
> a. For DS, the uncollectible amounts included in rates shall be the amount equal to the DS uncollectible component as stated in the compliance DS tariff sheets as a dollar amount per customer, per month multiplied by the number of customers. The DS uncollectible component would be included within the stated DS monthly customer charge and not appear on customer bills as a separate line item. The AIU will provide Surrebuttal Testimony on this item in the pending rate case.

The parties have agreed to a similar provision with respect to Rider GUA. (Ameren Ex. 58.0 2d Rev. (Millburg Sur.), p. 5.) The AIUs propose that the "average amount per customer per month" be listed in the appropriate DS tariff in the Terms and Conditions section. (Ameren Ex. 55.0 Rev. (Jones Sur.), p. 22.) These amounts will be tracked within the AIUs' billing system and serve as the base amount of uncollectible included in rates, required for use in conjunction with Riders EUA and GUA. (Id.; Ameren Ex. 58.0 2d Rev., p. 5.) The AIUs' calculations will be updated to conform to the expense level authorized by the Commission at the conclusion of the rate case. The AIUs and Staff have agreed to this resolution.

2. Gas

a. *Rate Limiter or Capping Mechanism*

The AIUs proposed a rate capping mechanism that would limit individual rate class rate increases to 20% or 30% depending on the utility. Staff supports this proposal and no other party addressed this issue. Thus, the AIUs' proposed rate capping mechanism is a resolved issue.

The AIUs' current rates generate different rates of return for each rate class. (Ameren Ex. 16.0G (Normand Dir.), p. 15.) One of the AIUs' rate design goals in these proceedings is to move each of the utilities' rate classes closer to its revenue requirement by assuming an equalized revenue requirement for each rate class within each of the AIUs. (Id., p. 20.) An equalized class revenue requirement would be those revenue levels required for each rate class if they were to eliminate all inter-class subsidization and produce exactly the same ROR as the overall level for each of the AIUs. (See ICC Staff Ex. 9.0 (Harden Dir.), p. 15.)

AIU witness Normand, however, determined that adopting an equalized ROR level for each rate class of the AIUs would result in rate increases that "in many instances were so great as to create the potential for disruptive increases." (Ameren Ex. 16.0G, p. 20.) The AIUs, therefore, propose to limit the rate increase for each rate class to a specified percentage over present rates to avoid these adverse bill impacts. (Id., pp. 20-21.) If a rate class rate increase is limited by the rate capping mechanism, then the amount of that rate class' revenue requirement that is above the cap would be recovered from the rate classes that have not reached the cap. (See id., p. 21.) The AIUs propose a 20% cap for AmerenIP customers and a 30% cap for AmerenCILCO and AmerenCIPS customers. (Id., pp. 20-21.) The higher increase for AmerenCILCO and AmerenCIPS addresses a much larger difference in ROR and revenue deficiency levels for certain rate classes. (Id.)

Staff witness Harden agrees with the AIUs' proposed gas rate capping mechanism and recommends that the Commission approve it. (ICC Staff Ex. 9.0, p. 17.) Ms. Harden testified that the AIUs considered the bill impacts of a customer's overall annual bill. (Id.) She also noted that while some inter-class subsidies will be necessary, those subsidies will lessen the impact of the rate increase for many AIU customers. (Id.) According to Ms. Harden, the AIUs' proposed rate capping mechanism mitigates the concerns associated with adopting the full cost of service results and the prospect of unfavorable rate impacts that could otherwise result for some rate classes, especially due to the reclassification of rate class definitions for AmerenCILCO and AmerenCIPS. (Id.) Finally, Ms. Harden testified that the rate capping mechanism levels the distribution of the increase and spreads the proposed interclass subsidy over all other rate classes. (Id.)

Staff supports the AIUs' proposed rate capping mechanism. No other party commented on the AIUs' approach. Accordingly, the record supports approval of the AIUs' effort to move their customers closer to a levelized cost of service in these rate cases subject to the proposed rate capping mechanism that avoids rate shock.

b. *Overall Rate Design (Scale to Final Revenue Targets)*

The AIUs proposed a rate design using the cost of service based on each of the AIUs' revenue requirements. Staff supports the AIUs' overall rate design subject to adjustment for the final revenue requirements approved by the Commission. (See generally ICC Staff Ex. 22.0 (Harden Reb.), pp. 5-10.) Because the AIUs agree with the Staff's proposed method for such adjustments, and no other party addressed this issue, the AIUs' overall rate design and the agreed upon adjustments are resolved issues.

Ameren witness Normand presented the AIUs' proposed rate design his direct testimony. (*See* Ameren Ex. 16.0G (Normand Dir.), pp. 24-33; Ameren Ex. 16.12G.) Once revenue targets were established for each of the AIUs' rate classes, the AIUs' rate design process was guided by three general principles moving rates towards a reasonable customer impacts: (1) considering the rate capping mechanism described above; (2) eliminating inconsistencies between the AIUs' rate designs; and (3) emphasizing the 80%/20% fixed/variable thresholds authorized by the Commission for GDS-1 and GDS-2 rates in the AIUs' last approved rate cases. (Ameren Ex. 16.0G, p. 23.)

Mr. Normand updated his gas cost of service studies in his rebuttal testimony to address certain mathematical oversights including updates to the Account 904 uncollectible allocation for AmerenCILCO and Ameren CIPS, as well as the updates to the on-system storage cost allocations. (Ameren Ex. 27.0 (Normand Reb.), pp. 2-6.)

Mr. Normand testified that his corrections to the Account 904 uncollectible allocation for AmerenCILCO and Ameren CIPS (see Sec. VI.C.2.a., supra) would have no effect on the AmerenIP rate design, and only a *de minimis* effect on the AmerenCILCO and Ameren CIPS rate design – especially when considering the total revenue requirement of each class, and the proposed rate caps and uniformity goals. (Ameren Ex. 27.0, p. 3.) While the rate design effects on AmerenCILCO and Ameren CIPS would be *de minimis*, those effects should be factored into the final rate design approved by the Commission. (Id.)

On the other hand, Mr. Normand testified that his changes to the customer class ROR as a result of the on-system storage allocation correction (see Sec. VI.C.3.b., supra) did not impact his rate design recommendations. (Ameren Ex. 27.0, p. 6.) He specifically stated that:

> the results are rather small and have little impact on my initial rate design proposals for all of the AIUs. By far the most important consideration was again the goals of rate uniformity and revenue caps for the AmerenCIPS and AmerenCILCO, which these changes do not diminish.

(Id., lines 126-29.) Hence, this correction does not factor into the final rate design.

Staff witness Harden agrees with and recommends approval of the AIUs' overall proposed rate design. (ICC Staff Ex. 9.0 (Harden Dir.), pp. 18, 37-38; ICC Staff Ex. 22.0 (Harden Reb.), p. 5.) Ms. Harden testified that the AIUs properly accounted for the Commission's directives from the last rate order, for bill impacts, and that the AIUs have implemented a capping mechanism to moderate increases based on the goal of uniformity among the Companies. (ICC Staff Ex. 9.0, p. 18.)

Ms. Harden proposed a method for adjusting the AIUs' proposed rates to account for the difference between the revenue requirement proposed by the AIUs and the revenue requirement proposed by Staff witness Ebrey. (ICC Staff Ex. 22.0, pp. 5-6.) In essence, Ms. Harden proposes to scale the AIUs' proposed rates by the ratio of Ms. Ebrey's revenue requirement for each utility to the AIUs' proposed revenue requirement for each utility. (Id., p. 6.) Ms. Harden's proposed adjustment does not alter the AIUs' general rate design. Instead, it simply increases or decreases the rates in proportion to the change in the revenue requirement.

The AIUs agree that it is proper to adjust the final rates based on the revenue requirement approved by the Commission for each of the Companies. Moreover, the AIUs are in general agreement with Ms. Harden's approach of scaling the AIUs' proposed rates based on the final revenue target level. (Ameren Ex. 57.0 (Normand Sur.), p. 2.)

Consequently, the Commission should accept the AIUs' proposed rate design as adjusted by Mr. Normand in his rebuttal testimony. If, however, the Commission approves different revenue requirements for the AIUs, the Commission should adopt Ms. Harden's approach of scaling the AIUs' proposed rates based on the final revenue target level.

c. *Interval Meter Data Access Fees*

The AIUs proposed to implement an interval meter data access fee that would permit the AIUs to recover the cost of providing optional Daily Usage Information Service. Staff and the parties agree that the proposed interval meter data access fee is reasonable. The interval meter data access fee is a resolved issue.

The AIUs no longer need real-time data connections to their GDS-2 and GDS-3 customer meters. (Ameren Ex. 17.0G Rev. (Millburg Dir.), p. 13.) Many of these customers have expressed a desire to maintain access to daily usage information. In response, the AIUs proposed an optional Daily Usage Information Service with a data access fee that would reflect the cost of modifying the existing metering to make it capable of transmitting the daily meter information to the AIUs. (Id.) The AIUs initially estimated that the installation of a modem and associated equipment required necessary to provide this optional service would result in an upfront, one-time charge of $2,400. (Id.) The AIUs later refined that analysis and determined this optional service would require a lower one-time installation fee of either $1944 (if an Electronic Pressure Corrector – Pulse Accumulator is required) or $812.25 (if no Electronic Pressure Corrector – Pulse Accumulator is required). (Ameren Ex. 48.0 Rev. (Millburg Reb.), p. 4.) The AIUs proposed a $5.00 monthly service charge for this optional service. (Ameren Ex. 17.0G Rev., p. 13.)

Staff witness Boggs recommended approval of the AIUs' updated installation fees of $1944 and $812.25, as well as $5.00 monthly service charge. (ICC Staff Ex. 10.0 (Boggs Dir.), p. 24; ICC Staff Ex. 23.0 (Boggs Reb.), p. 3.) GFAI also approved this provision, by stating that it supported making the service available as an option at a fee that recovers actual costs. (GFAI Ex. 1.0G (Adkisson Dir.), p. 5.)

The AIUs proposed (Ameren Ex. 48.0 Rev., p. 5.) and the Staff accepted (ICC Staff Ex. 23.0, p. 3) the following new tariff language to implement the updated installation charge:

> If Customer elects such service, the Company may be required to install a remote monitoring device to provide daily usage information to Customer. If Company is required to install a remote monitoring device in order for Customer to receive Daily Usage Information Service, Customer will be required to pay Company for the cost of equipment and installation, prior to receiving service, as follows.
>
> $1944.00, for each meter where installation of a pulse accumulator is required.
>
> $812.25 for each meter where installation of only a modem is required.

(Ameren Ex. 48.0 Rev., p. 5.)

No party addressed the proposed interval meter data access fee. The Commission should accept the proposed Daily Usage Information Service or the updated fees shown in the proposed tariff language.

d. *Calculation of "Highest Average Daily Use"*

The AIUs proposed to determine the eligibility of a number of rate classes based on the customers "highest average daily usage." (Ameren Ex. 17.0G Rev. (Millburg Dir.), Table titled "Overview of Proposed Tariff Changes," pp. 4-6; <u>see</u> <u>also</u> Sec. VII.C.1.a., <u>infra</u>) AIU witness Millburg testified that the "highest average daily use is determined by dividing the customer's total usage in a billing period by the number of days in that billing period." (Ameren Ex. 48.1; see also Ameren Ex. 48.0 Rev. (Millburg Reb.), p. 8.) GFAI witness Adkisson agreed with this method for calculating a customer's highest average daily usage. (GFAI Ex. 1.0G (Adkisson Dir.), p. 3.) No other party commented on the calculation of a customer's highest average daily usage. Accordingly, the Commission should accept the proposed method for calculating a customer's highest average daily usage for use in determining a customer's rate eligibility.

e. *Transportation Tariff (Rider T)*

(1) NAESB Intraday Nomination Cycles

The AIUs initially proposed to retain the existing nomination deadlines for transportation customers. Staff and CNEG, on the other hand, proposed that the AIUs permit transportation customers to submit nominations based on the North American Energy Standards Board's ("NAESB's") Intraday 1 and Intraday 2 schedules. The AIUs, Staff, and CNEG have agreed that the new tariff language implementing a single "same day" nomination schedule at 7:30 a.m. (rather than the NAESB Intraday 1 and Intraday 2 schedules) is a reasonable solution to these issues. The same day nomination reasonably balances the AIUs' interest in maintaining system reliability with the customers' interest in additional flexibility. The NAESB intraday nomination issue, therefore, is a resolved issue.

Transportation customers submit nominations to the AIUs to let the AIUs know how much natural gas the transportation customer wants to ship on a given day. (Ameren Ex. 22.0G (Dothage Dir.), p. 5.) Currently, the AIUs permit transportation customers to submit nominations at 11:30 a.m. and 4:00 p.m. to identify the gas to be delivered on the next gas day. (Id.; see also AmerenCIPS's Rider T - Gas Service Schedule Ill. C.C. No. 20, 2nd Revised Sheet Nos. 25.009-25.010; AmerenIP's Rider T - Gas Service Schedule Ill. C.C. No. 37, 1st Revised Sheet

Nos. 25.009-25.010; AmerenCILCO's Rider T - Gas Service Schedule Ill. C.C. No. 19, 1st Revised Sheet Nos. 25.009-25.010.)

The AIUs' tariffs require the utilities to use their best efforts to accommodate any other off-cycle nominations. (Id., pp. 5-6; see also AmerenCIPS's Rider T - Gas Service Schedule Ill. C.C. No. 20, 2nd Revised Sheet Nos. 25.009-25.010; AmerenIP's Rider T - Gas Service Schedule Ill. C.C. No. 37, 1st Revised Sheet Nos. 25.009-25.010; AmerenCILCO's Rider T - Gas Service Schedule Ill. C.C. No. 19, 1st Revised Sheet Nos. 25.009-25.010.) The AIUs, however, currently do not provide transportation customers with the firm right to submit intra day nomination changes – *i.e.,* changes submitted on the same day that the nominations would take effect.

In the final order from the last rate case proceedings, the Commission directed the AIUs to provide the cost of providing all four NAESB nomination cycles – including intraday nominations. Docket 07-0585 (cons.), Final Order (Sept. 24, 2008), p. 323. The AIUs provided an estimated cost of providing all four NAESB nomination cycles. (Ameren Ex. 22.0G, p. 6.) Based on those estimates, as well as their experiences under the existing nomination deadlines, the AIUs initially recommended that the Commission should not require the AIUs to implement all four NAESB nomination cycles. (Id., p. 7.) On the other hand, Staff witness David Sackett and CNEG witness Kawczynski sought implementation of same-day nomination options, in addition to the existing day-ahead nomination schedules. (ICC Staff Ex. 14.0 (Sackett Dir.), p. 8; CNE-Gas Ex. 1.0 (Kawczynski Dir.), p. 22.) No other party addressed the issue of nomination deadlines.

The AIUs, Staff, and CNEG – the only parties addressing this issue – have agreed that adding a same-day nomination at 7:30 a.m. on the same day as gas flow is a reasonable resolution to the issues of intraday gas nominations for transportation customers as those matters were addressed by AIU witness Dothage, Staff witness Sackett, and CNE-Gas witness Kawczynski so long as the AIUs would not plan to materially alter their computer systems to automate the receipt of "Same-Day" nominations. More specifically, in a series of data requests, these parties agreed that it would be reasonable to adopt the following tariff language implementing a new "Same-Day" nomination as part of the Nomination of Customer-Owned Gas section of each of the AIUs' Rider-T tariffs:

> Same-Day
>
> Customer desiring a change in Nomination for transportation of Customer- Owned Gas after the Intra-Day deadline specified above shall notify Company by 7:30 A.M. CST of the business day on which the Nomination is to take effect, subject to confirmation by the pipeline. Company may accept such change to Customer's Nomination if the Company determines in its sole discretion that such a change to Nomination will not adversely impact the operation of the Company's gas system or adversely impact Company's purchase and receipt of gas for other Rates or Riders.

(Staff Resp. to AIU-ICC 37.01; CNEG Resp. to AIU-CNEG 3.01; (Ameren Group Hearing Ex. 1).) Those Data Request responses identify corresponding changes to the section titled "Intra-Day." (Id.) As part of those data requests, the AIUs agreed not to alter their computer systems materially to automate the receipt of these "Same-Day" nominations. (AIUs' Resp. to DAS 14.01 (Staff Group Ex. 1).)

The Commission should accept the joint proposal of the AIUs, Staff, and CNEG to modify the AIUs' Rider Ts to implement the 7:30 a.m. same-day nomination. It represents a reasonable solution to the issues presented by these parties in pre-filed testimony and no other party addressed these issues.

(2) Notice for OFOs and Critical Days

The AIUs initially proposed to retain the existing tariff language regarding prior notice of Operational Flow Orders ("OFOs") and Critical Days. Staff and CNEG, on the other hand, asked that the AIUs provide significantly greater notice before the effectiveness of an OFO or Critical Day. The AIUs, Staff, and CNEG have agreed that the new tariff language implementing an expanded notice policy (including a Commission reporting requirement) is a reasonable solution to these issues. Thus, the OFO and Critical Day notice issue is a resolved issue.

In its final order in the AIUs' previous rate cases, the Commission required the AIUs to provide "an analysis of its distribution systems identifying those areas that would not be immediately affected by a single event on the associated interstate pipeline(s)." Docket 07-0585 (cons.), Final Order (Sept. 24, 2008), p. 345. The Commission stated that "[t]he analysis must also address with specifics whether AIU could provide notice in such areas comparable to the notice provided by Nicor and Peoples." Id.

Ameren witness Seckler provided the required distribution system analyses. (Ameren Ex. No. 23.0G (Seckler Dir.), pp. 3-10; Ameren Ex. No. 23.1G; see, also, Ameren Ex. No. 45.0 Rev. (Seckler Reb.), pp. 2-7.) Ms. Seckler concluded that it was not always possible for the AIUs to provide advance notice of Operational Flow Orders or Critical Days. (Ameren Ex. No. 23.0G, p. 9; see, also, Ameren Ex. No. 45.0 Rev., p. 5.)

Staff witness Sackett proposed that the AIUs make a good faith effort to give a 24-hour notice of Operational Flow Orders or Critical Days. (ICC Staff Ex. 14.0 (Sackett Dir.), p. 18.) CNEG witness Kawczynski proposed that the AIUs provide notice "as far in advance as possible, normally not less than two hours, unless conditions warrant immediate implementation of the Critical Day or OFO." (CNE-Gas Ex. 1.0 (Kawczynski Dir.), p. 10, ll. 211-213.)

In response to the concerns expressed by Staff and CNEG, the AIUs agreed to provide advance notice of a Critical Day or OFO as far in advance as reasonably possible. Moreover, the AIUs agreed to submit a report to the Commission if the AIUs could not provide a 24-hour notice. In particular, the AIUs stated that they were willing adopt the following tariff language as part of the Rider T section titled "System Integrity Protection":

> The Company shall provide notice of a Critical Day and OFO as far in advance as reasonably possible, normally not less than two hours, unless the Company believes conditions warrant immediate implementation of the Critical Day or OFO. If the Company issues a Critical Day or OFO notice within 24 hours of the Critical Day or OFO taking effect, the Company will report to the Commission indicating why customer notice of less than 24 hours was necessary.

(Ameren Ex. No. 45.0 Rev., p. 6, lines 122-29.) Ms. Seckler testified that this resolution resolves the Critical Day and OFO notice issued in the previous rate cases. (Id., p. 7)

CNEG witness Kawczynski agreed with the proposed language and "urges the Commission to accept the Rider T amendment" described above. (CNE-Gas Ex. 2.0 (Kawczynski Reb.), p. 3, lines 46-47.) Mr. Kawczynski further testified that the proposed tariff language addresses the issues he raised in these proceedings and previous proceedings. (Id.)

Staff witness Sackett also recommended that the Commission approve the AIU's proposed tariff language as a resolution to the issue of Critical Day and OFO notices. (ICC Staff Ex. 27.0R (Sackett Reb.), p. 4.) Mr. Sackett agreed that the AIUs should provide the justification report to the Commission within two business days after declaring a Critical Day or OFO. (Staff Resp. to AIU-ICC 32.20 (Ameren Group Hearing Ex. 1).) The AIUs agree that it would be reasonable for them to provide the justification report (when necessary) to the Director, Energy Division within two business days after declaring an OFO or Critical Day without at least a 24 hour notice. (Ameren Ex. 65.0 (Seckler Sur.), pp. 3-4.)

The Commission should accept this reasonable conclusion to the issue of prior notice of OFOs and Critical Days. The AIUs have provided the analysis previously required by the Commission. More importantly, all parties addressing the issue in these cases agree that the proposed tariff language resolves the issues. The proposed tariff language provides transportation customers with as much advance notice as is reasonably possible. The justification reports will provide the Commission with information necessary to consider this issue if it arises in the future rate cases.

3. <u>Electric</u>

a. *Rider PER*

The AIUs proposed to modify Rider PER, so that it points to this docket as establishing BGS base prices, replacing a reference to the rate redesign case, Docket Nos. 07-0164 (cons.) (Ameren Ex. 16.0E 2d Rev. (Jones Dir.), p. 50.) This change is necessary, to the extent the Commission accepts the AIUs' proposal to adjust BGS-1 and BGS-2 prices in this proceeding.

In response, Staff suggested one minor change - that Rider PER, Sheet No. 31.008 should be modified to read as follows:

> The base Retail Supply Charges resulting from the ICC Order associated with Docket Nos. 09-0306 – 09-0311 (Cons.) shall provide the initial baseline for changes in overall electric charges for any price classification.

(ICC Staff Ex. 8.0 (Rukosuev Dir.) p. 30.) The AIUs agree to this modification, and thus have reached an accord with respect to this issue.

b. *Rider RDC*

The AIUs proposed a change to Rider RDC, to ensure that the phrases "Demand" and "Billing Demand" are not interchangeable terms. (Ameren Ex. 16.0E 2d Rev. (Jones Dir.), p. 49.) Presently, "Demand" and "Billing Demand" share the same definition, but the term "Billing Demand" is adjusted within both DS-3 and DS-4 to carry a different meaning. (Id., p. 48.) In response, Staff suggested that the term "billing demand" should not be capitalized. (ICC Staff Ex. 8.0 (Rukosuev Dir.) p. 31.) The AIUs have consented to that revision, thus, this issue is uncontested. (Ameren Ex. 40.0 2d Rev. (Jones Reb.) p. 20.)

c. *Rider BGS*

Electric energy charges are charged through Rider BGS. (Ameren Ex. 16.0E 2nd Rev. (Jones Dir.), p. 43.) If a customer takes this optional service, the customer will have a constant Supply Cost Adjustment (SCA) applied to each kWh of use. (Id., p. 52.) A special electric space-heat discount was reinstated a power rate for customers that previously received the special Rider BGS prices available to small general service customers. (Id.)

Staff and the AIUs are in general agreement concerning the proposed rate design for BGS-1 and BSG-2. (Id.) The AIUs and Staff both recommend approval of a 10% variable price increase to the tail block DS/BGS-2 prices. (Ameren Ex. 55.0 Rev. (Jones Sur.), p. 11; Ameren Ex. 16.5E; Ameren Ex. 16.9E.) The AIUs and Staff also both urge approval of the 13% variable price increase for BGS-1. (Id., p. 10.)

The Commission should adopt the proposed Rider BGS rate design.

d. *Rider QF*

The AIUs propose to eliminate a provision in Rider QF that allows the AIUs to refuse to accept output from a qualifying facility when sale of output does not permit the AIUs to avoid costs. (Ameren Ex. 16.0E Rev. (Jones Dir.), p. 49.) The AIUs currently use energy purchases to offset power procured on behalf of fixed-price customers. (Id.) Qualifying Facility (QF) purchases usually influence the quantity of energy the AIUs buy and sell through the MISO-administered markets as the AIUs balances their fixed price energy portfolio. (Id.) As long as there is a MISO-administered market, the AIUs do not anticipate a situation where sale of output from a customer's QF would permit the AIUs to avoid costs. (Id., p. 50.) As such, the AIUs propose to eliminate this section. No party opposes this revision. Therefore, the AIUs believe this is a resolved issue.

e. *Rider HMAC*

Costs related to hazardous materials claims are recovered under the Hazardous Materials Adjustment Clause, or Rider HMAC. (ICC Staff Ex. 1.0 (Ebrey Dir.) p. 29). The HMAC Base Amount, as defined in Rider HMAC, is the amount of HMAC Costs reflected in the test year in the most recent electric rate case Commission Order. (Id., p. 40.) This amount is needed to determine the amount to be withdrawn or deposited annually into the HMAC Cost Fund. (Id.) Staff observed that the BASE amount included in AmerenIP's revenue requirement is $411,889 and requested that the final order in this proceeding clearly indicate this BASE amount for ease in applying Rider HMAC in future periods. (Id.) The AIUs agree that the HMAC BASE amount included in AmerenIP's revenue requirement is $411,899. (ICC Staff Ex. 15.0 (Ebrey Reb.), p. 6.)

f. *Miscellaneous Tariff Language Changes*

The AIU requested approval of several miscellaneous tariff provisions in its filing. Those changes were identified and addressed by Staff witness Mr. Rukosuev. (See Staff Ex. 8.0) In testimony, the AIU and Staff agreed upon all language differences between Mr. Rukosuev and the Companies. One item, however, remains unresolved in part. In Mr. Rukosuev's testimony, he addressed a proposed $170 meter reading fee for certain non-residential customers that fail to provide meter access or a telephone connection over which the AIU could electronically access meter data. (Id., pp. 4-7) Mr. Rukosuev conditionally agreed upon such a charge in testimony and data requests. The AIU do not objection to Mr. Rukosuev's conditions and have inserted what it believes is the legally appropriate tariff language addressing all of Mr. Rukosuev's concerns. That language is attached hereto as Appendix H.

g. *Supply Cost Adjustments for Rider PER*

(1) Supply Procurement Adjustment – Rider PER

The AIUs propose a detailed plan for recovering the costs related to the AIUs' power supply through the Supply Cost Adjustments. The cost components recovered through the Supply Cost Adjustments are the Supply Procurement Adjustment, the power supply portion of the Cash Working Capital Adjustment, and the power supply portion of the Uncollectibles Adjustment. (Ameren Ex. 2.0E Rev., p. 28.) In response, Staff proposed one change to the Supply Procurement Adjustment and two changes to the Uncollectibles Adjustment. Those changes are: (1) a corrected amount for costs associated with the procurement of power; (2) the uncollectibles factors for recovery under Rider PER should be consistent with the uncollectibles to be recovered through base rates; and (3) the allocation of write-offs between gas and electric service for combination customers should be based on the relative revenues for each type of service. (ICC Staff Ex. 15.0, p. 25.)

The AIUs agree with Staff's recommendation that $1,278,100 should be approved as the Supply Procurement Adjustment component of Rider PER. (ICC Staff Ex. 15.0, p. 6, Attachment B.) On rebuttal, Staff accepted the AIUs' proposal for the uncollectibles percentages based on net write-offs as a percentage of revenues, using calendar years 2007 and 2008 and year-to-date September 2009. Finally, Staff withdrew its third recommendation. (ICC Staff Ex. 15.0, pp. 25-26.) Therefore, this issue has been resolved.

(2) Uncollectibles Factor

The AIUs initially proposed to normalizing both electric and gas uncollectibles using a three-year weighted average of 2007-2008 actual and 2009 budgeted net write-offs, divided by revenues to determine the write-off percentage. (Ameren Ex. 29.0 Rev., p. 8.) Staff, AG-CUB, and IIEC, however, all recommended normalizing both electric and gas uncollectibles using a three-year weighted average of 2006-2008 rather than 2007-2009. (See, e.g., AG-CUB Ex. 4.0, p. 19.)

In an effort to minimize the issues in this proceeding, the AIUs modified their calculation of uncollectibles factors so that they now use only the most recent actual information for the period January 2007 through September 2009. (Ameren Ex. 29.0 (Rev.), p.9.) The AIUs agreement to revise the calculation of the uncollectibles factors addresses Staff's concerns because the new calculation is based entirely on actual information – not projections. (Id., p. 9.) This method is preferred, because it reflects the fact that the legislative rate freeze ended on January 2, 2007, which resulted in a higher level of uncollectibles and subsequent write-offs.

(Id.) Staff, AG-CUB and IIEC all accept the AIUs' revised methodology, and this issue has been resolved. (Ameren Ex. 51.0, p. 6.)

Staff, AG-CUB, and IIEC all initially recommended normalizing both electric and gas uncollectibles using a three-year weighted average of 2006-2008 net write-offs, divided by revenues to determine the write-off percentage. (See, e.g., AG-CUB Ex. 4.0 (Effron Reb.), p. 19.) The AIUs, on the other hand, use 2007-2008 actual and 2009 budgeted net write-offs and revenues. (Ameren Ex. 29.0 Rev. (Stafford Reb.), p. 8.) The AIU method reflects the fact that the legislative rate freeze ended on January 2, 2007, which resulted in a higher level of uncollectibles and subsequent write-offs. (Id.) Staff, AG-CUB and IIEC all now accept the AIUs' proposed methodology, and this issue has been resolved. (Ameren Ex. 51.0 2d Rev. (Stafford Sur.), p. 6.)

h. *DS-4 Reactive Demand Charge*

The AIUs have developed the proposed price for the Reactive Demand by examining the incremental cost of installing new capacitor banks, and have determined a simple average cost of about $0.30/kVAR for facilities installed at primary voltages and $0.63/kVAR for facilities installed at 34.5 kV and/or 69 kV. (Ameren Ex. 16.0E 2nd Rev. (Jones Dir.) p. 37.) The cost range of facilities is $0.15/kVAR to $0.73/kVAR. (Id.) The overall average percentage increase for all DS-4 customers combined for all of the AIUs (excluding the impact of the Distribution Tax) is approximately 21%. (Id., p. 38.) A 21% increase to the Reactive Demand Charge yields $0.29/kVAR, and is the price proposed by the AIUs. (Id.) The proposed charge is near the incremental cost of capacitor banks, which gives customers an economic choice to allow AIUs to correct for potential voltage issues on the delivery system, or improve their power factor on the customer's side of the meter. (Id.) As a result, the Distribution Delivery Charge for DS-4 is lower than it otherwise would be in the absence of the Reactive Demand Charge. (Id.)

The AIUs propose that the underlined language be added to the Company's Standards and Qualifications on Sheet 4.002:

> "**D. Requirements of Customer's Load**
>
> 2. Rate DS-1, DS-2, and DS-3 are expected to maintain a power factor in the range of 90% lagging to 90% leading during all periods of normal operation. Customer shall install corrective equipment necessary to meet this requirement on its side of the Company's or MSP's meter. Rate DS-4 Customers are expected to maintain a power factor in the range of 95% lagging to 95% leading during all periods of normal operation. DS-4 customers who maintain a power factor in the range of 95% lagging to 95% leading will pay the Reactive Demand Charge specified in the DS-4 tariff. Customers who maintain a power factor outside of the range of 95% lagging to 95% leading will pay the Reactive Demand Charge specified in the DS-4 tariff, and are also subject to charges for the corrective actions listed in the succeeding paragraph.
>
> When Customer's power factor is outside of the specified ranges, the Company may at its sole discretion, after notice is given, install corrective equipment on its side of the meter. Customer will be charged a lump sum amount, in accordance with the Excess Facilities provision of this tariff, for the current cost of such equipment and the cost of any subsequent additions to or replacement of such equipment whenever said future installations occur. Where Company completes the installations of corrective equipment, as described above, for a Customer taking service under Rate DS-4, all Reactive Demand charges associated with the existing power factor condition, where applicable, will be waived."

Staff recommends that the Commission order the AIUs to adopt the above language, so that customers have more accurate information about the applicability of reactive demand charges under Rate DS-4. (ICC Staff Ex. 24.0R (Rockrohr Reb.) p. 11-12.)

C. Contested Issues

1. Gas

a. *Availability Tariff Provisions*

In the last rate cases, AmerenCILCO, AmerenCIPS, and AmerenIP made great steps toward greater uniformity among the utilities' tariffs. The Commission directed the AIUs to continue that move toward uniformity. Central Illinois Light Co. et al., 07-0585 (cons.), Final Order (Sept. 24, 2008), pp. 335-36; see also Ameren Ex. 17.0G Rev. (Millburg Dir.), p. 3.) The AIUs have proposed a number of changes to their tariffs in these rate cases with the goal of achieving uniformity in tariff provisions and satisfying the Commission's directive. (Id.)

AmerenCILCO, AmerenCIPS, and AmerenIP all have similar non-residential rate classes GDS-2 through GDS-4. However, the Availability (or eligibility) provisions of those rate classes differ from company to company, however. In the name of uniformity, the AIUs now propose that AmerenCILCO and AmerenCIPS adopt the usage-based Availability provisions currently employed by AmerenIP for GDS-2, GDS-3, and GDS-4. (Id., p. 10.) In addition to addressing the Commission's uniformity directive, these changes benefit the AIUs' operating practices and rate administration, as well as the customers.

In considering its proposed Availability thresholds, the AIUs sought to use the existing Availability provisions of one of its companies. (Ameren Ex. 58.0 2d Rev. (Millburg Sur.), p. 13.) The AmerenIP tariff currently assigns customers to rate classes GDS-2, GDS-3, and GDS-4 based on each customer's actual highest daily average usage (or "HDA"). The AmerenIP Availability provisions provide customers with an immediate and definitive classification method using easily accessible information. (Ameren Ex. 17.0G Rev., p. 9.) On the other hand, the current AmerenCILCO and AmerenCIPS Availability criterion instead rely upon methods of meter size, calculation of connected gas load, and definition of "general" use. (Id.)

The AIUs believe that usage-based Availability provisions based on usage are the easiest for their customers to understand and Staff to administer. (Id., p. 10) Of the three companies, only AmerenIP currently employs a usage-based Availability methodology for all of its gas delivery tariffs that can be efficiently administered efficiently. Moving AmerenCILCO and AmerenCIPS to the AmerenIP Availability criterion method will provide customers of AmerenCILCO and AmerenCIPS customers that same immediate and definitive classification method using easily accessible information.

Staff witness Harden recommends approval of the AmerenIP usage-based Availability criterion for the GDS-2 through GDS-4 customers of AmerenCIPS and AmerenCILCO. (ICC Staff Ex. 9.0 (Harden Dir.), p. 14.) She testified that the adjustments "provide more uniformity in the Companies' rate class structures as well as uniformity with the Ameren electric tariffs." (Id., lines 279-80.) She believes that the resulting uniformity would alleviate potential confusion. (Id.)

The AIUs analyzed the major cost differences in the meters that are currently used to serve the various customer groups, in order to determine whether the usage thresholds should be adjusted from the current AmerenIP levels. (Ameren Ex. 58.0 2d Rev., pp. 13-14.) That analysis indicated that the existing AmerenIP usage thresholds follow the major cost differences in the meters used to serve the various customer groups. (Id.) The AIUs conducted the cost of service studies and individual customer impact studies on customers of all three utilities using the Average Daily Usage thresholds proposed in its tariffs. (Id.) The result of this change for most gas customers will be some migration from GDS-4 to GDS-3 or from GDS-3 to GDS-2. (Ameren Ex. 17.0G Rev., p. 9.) Customers moving down a rate class as a result of this change should not face detrimental bill impacts. (Id.) Ms. Harden also reviewed the bill impacts of this change. She found that the proposed rate class definition changes and resulting reclassifications would result in comparable increases for the majority of the AIU customers. (ICC Staff Ex. 9.0, p. 14.) After reviewing the rate impacts – with special attention to the rate classification changes – Ms. Harden concluded that "the rate class changes and steps toward uniformity are appropriate." (Id., p. 42, lines 892-93.)

GFAI supports the AIUs' goal of achieving uniformity of in their tariff provisions. (GFAI Ex 1.0G, p. 4.) But GFAI objects to two elements of the AIUs' proposal. First, GFAI argues that a customer's highest daily average usage should be based only on the customer's usage in the months from December through March. (Id.) GFAI also argues that the cutoff between GDS-3 and GDS-4 should be based on the annual usage criteria currently employed at AmerenCILCO rather than highest daily average usage. (Id.) The following table summarized the key differences between the AIUs' proposal and GFAI's proposal.

Although these issues will be addressed below, it is important to note that GFAI has not conducted any analysis, or presented any information on the impact of adopting its preferred methodology, even though their proposal changes the Availability threshold would affect the 70,800 non-residential customers of the AIUs currently served under standard tariffs. Because the impact of GFAI's methodology is so far reaching, and completely unsupported, it should be rejected in favor of the AIUs' more logical and heavily supported proposal.

	AIUs' Proposed Availability Provision	GFAI's Proposed Availability Provision
GDS-2	Upper Limit: HDA < 200 therms	Upper Limit: HDA < 200 therms – measured only in the billing months of December through March
GDS-3	Lower Limit: HDA ≥ 200 therms Upper Limit: HDA < 1000 therms	Lower limit: HDA ≥ 200 therms – measured only in the billing months of December through March Upper Limit: annual usage of 250,000 therms. Alt. Upper Limit: HDA < 1000 therms – measured only in the billing months of December through March
GDS-4	Lower Limit: HDA ≥ 1000 therms	Lower Limit: annual usage of 250,000 therms. Alt. Lower Limit: HDA ≥ 1000 therms – measured only in the billing months of December through March

Although GFAI's objections are addressed below, it is important to note upfront that GFAI has not conducted any analysis, or presented any information on the impact of adopting its preferred methodology, even though their proposal changes the Availability threshold would affect the 70,800 non-residential customers of the AIUs currently served under standard tariffs. Because the impact of GFAI's methodology is so far reaching, and completely unsupported, it should be rejected in favor of the AIUs' more logical and heavily supported proposal.

(1) The Highest Daily Average Usage Should Be Based On the Customers Usage During the Entire Year Not Just Over 4 months.

AmerenIP's rate class Availability is based on a customer's highest daily average usage as measured over a year. For instance, non-residential customers with a highest daily average usage of less than 200 therms are eligible for service under GDS-2. Under the AIUs' proposal, AmerenCIPS and AmerenCILCO would adopt the AmerenIP Availability structure.

GFAI agrees with the AIUs' proposal to base the GDS-2 upper limit and the GDS-3 lower limit on the customers' highest daily average usage. (GFAI Ex 1.0G (Adkisson Dir.), p. 3.) GFAI also agrees, as an alternative,[53] with AIUs' proposal to base the cutoff between GDS-3 and GDS-4 on the customers' highest daily average usage. (Id., pp. 3-5.) GFAI, however, contends that the highest average daily use calculation only should be performed using the customers' usage during the months of December through March. (Id.)

It is understandable that GFAI would pursue rate structures that are highly advantageous to its membership – a group whose primary gas usage typically occurs outside months of December through March. (GFAI Ex. 2.0G (Adkisson Reb.), p. 3, lines 46-47 ("A typical grain drier will use about 80% of its annual natural gas volume during harvest, which is about a two month period."); Ameren Ex. 48.0 Rev., p. 9.) The GFAI states that there is "little difference" between their proposal and the AIUs' proposed Availability criterion. (GFAI Ex 1.0G, p. 3.) That is incorrect. GFAI's proposal is materially different from the AIUs' proposal. By grossly understating the impact that their proposal will have on the AIUs' customers, GFAI fails to recognize that their proposed modification is likely to lead to an inequitable assignment of costs among customer classes. (Ameren Ex. 48.0 Rev., p. 9.)

In fact, under the GFAI proposal, it is very likely that many of the seasonal customers would move to a lower tariff class than would be justified, based on the investment and

[53] GFAI's primary recommendation is to base the cutoff on an annual usage limit but supports the highest daily average usage as an alternative. (GFAI Ex 1.0G (Adkisson Dir.), pp. 4-5.)

equipment needed to serve their loads. (Id.) GFAI's position for restricting highest daily average usage measurement to the December through March timeframe ignores that the bulk of the costs to build, operate, and maintain gas delivery systems are fixed charges which do not vary based on the time of year that the usage occurs, and that all users of the system should pay an equitable share of those costs. (Ameren Ex. 58.0 2d Rev., p. 11.) GFAI's proposal would result in customers using the system during non-peak periods paying *nothing* towards the fixed costs of operating the system. (Id.) The Commission previously recognized the need for all users of the system to pay their share of the fixed costs, regardless of the amount of gas they use or the time of year when the usage occurs, by placing 80% of fixed cost recovery into the Customer Charge for GDS-2 customers. Docket 07-0585 (cons.), Final Order (Sept. 24, 2008), p. 237; see also Ameren Ex. 58.0 2d Rev., p. 11-12.) The AIUs have maintained that apportionment of fixed costs within the Customer Charge in their rate design in this case. (Ameren Ex. 58.0 2d Rev., p. 11.)

Further, GFAI's proposal is unworkable, because customers could simultaneously qualify for GDS-2 and GDS-3 or GDS-4. (Id., p. 10.) For example, if a grain-drying customer had an average daily use of 1,500 therms during the September through November harvest season, and minimal usage for the rest of the year, under GFAI's proposal, the customer's annual usage could exceed 250,000 therms and result in the customer being assigned to GDS-4. The customer would then be required to implement daily balancing and install a phone line, and the AIU would need to install interval metering to record his usage appropriately. (Id.) However, this same customer plausibly would have an average daily usage of less than 200 therms per day during the non-harvest December through March timeframe, which would result in the customer being assigned to GDS-2 and able to balance monthly, with no need for a phone line or extensive metering. (Id.) This would not only cause confusion for customer, but also add ambiguity for rate administration, which would result in financial uncertainty for the recovery of the utility's approved revenue requirements. (Id.) Tariff applicability provisions that allow a customer to select between standard GDS rate classes without any meaningful change in usage patterns can also be detrimental to other customers over the long run, as rates are established in future rate cases. (Id.)

It appears that the intent of the GFAI proposal is to address the seasonal usage of its membership. But the AIUs' tariffs already recognize the different impacts that seasonal customers have on fixed and variable costs, and reflect that recognition in the billing components and associated charges of GDS-5. (Ameren Ex. 48.0 Rev., p. 10.) GDS-5 enables customers who use gas only on days when the average temperature is forecasted to be above 25 degrees Fahrenheit to avoid paying a demand charge. (Id.) Since the December through March timeframe is the time of year when it is most likely that the temperature will be 25 or lower, GDS-5 accomplishes GFAI's goal. (Id.) In fact, GFAI supports the proposed GDS-5, without reservation or condition. (GFAI Ex. 1.0G, p. 5.) Using a GFAI's proposed four-month calculation period to determine rate Availability would simply result in an inequitable assignment of fixed costs. (Ameren Ex. 58.0 Rev., p. 11.) Moreover, to add a seasonality component into the other gas delivery service tariffs is unsupported, redundant, and inconsistent with the goal of uniformity. Such a modification is not needed, because the provisions of the GDS-5 tariff already provide price signals to encourage customers to operate outside of the temperatures typically encountered during the December through March timeframe. (Id., p. 13.)

GFAI simply rehashes arguments from the last AIU rate cases. (Id., p. 12.) There, the Commission declined to endorse GFAI's positions, and expressed concern around the degree to which non-winter gas users are affecting the non-winter demand for gas, and the challenges associated with converting demand charges to volumetric charges. (Docket 07-0585 (cons.), Final Order (Sept. 24, 2008), pp. 334-35; Ameren Ex. 58.0 2d Rev., p. 12.) GFAI merely reiterates points already rejected, without providing any additional analysis to support them.

None of the AIUs currently base tariff Availability on the customers' highest daily average usage measured only from December through March. In this context, GFAI does not seek to apply the existing Availability provision of one of the AIUs to the other two AIUs. Instead, GFAI proposes entirely new Availability provisions for all three of the AIUs. The customers of all three utilities' would be impacted by the GFAI proposal. Yet, GFAI does not provide any rate design, cost allocation, or bill impact analysis. GFAI simply desires a change that it thinks will benefit its membership without any consideration of the potential impact on other customers. The AIUs, however, have prepared and presented a unified, consistent rate design plan supported by the appropriate analysis and consideration. Staff witness Harden also evaluated the AIUs' proposal in a consistent and complete manner.

The Commission should approve the AIUs' proposal to base tariff Availability on customers' highest daily average usage as measured over the entire year and reject GFAI's proposal to limit the measurement of customers' highest daily average usage to the months of December through March.

(2) The cutoff between GDS-3 and GDS-4 should be based on Highest Daily Average Usage, Not Annual Usage.

Under the existing AmerenIP tariff provisions, and AIUs' tariff Availability proposal, gas customers with highest daily average from 200 therms to less than 1,000 therms would be eligible for service under rate class GDS-3, and customers with a highest daily average of 1,000 or greater would be eligible for service under rate class GDS-4. The GFAI objects to the split between GDS-3 and GDS-4 service. Rather than the 1,000 therm highest daily average usage cutoff currently used by AmerenIP, GFAI proposes to use the maximum annual usage of 250,000 therms as the separator between GDS-3 and GDS-4 service.

Again, GFAI provides no analysis supporting its proposal to use a maximum annual usage of 250,000 therms criteria as the cutoff. Instead, GFAI supports its Availability proposal only with the claim that the 250,000-therm maximum annual usage limit is based on the existing lower limit of AmerenCILCO's GDS-4 rate class. (Id., p. 13.) But GFAI does not explain why it prefers AmerenCILCO cutoff to the AmerenIP cutoff. To determine Availability for GDS-3 using the GFAI methodology, the AIUs would use both a daily average calculation based on a four-month window (to determine the lower limit), as well as a total usage threshold that considers 12 months of usage (to determine the higher limit). (Ameren Ex. 48.0 Rev., p. 11.) The AIUs' proposal is easier for customers to understand, and for the AIUs to administer, because it relies only on a single calculation of the customer's highest daily average usage to determine both the upper and lower limits. Further, the AIUs' proposal is consistent with the Commission's directive in Docket Nos. 07-0585 et al. (Cons.) that the AIUs adopt uniformity of maximum use provisions for its non-residential gas tariffs. (Id.) GFAI's proposal, on the other hand, does not promote uniformity and clarity.

It is notable that GFAI actually supports using 1,000-therm highest daily average usage cutoff between GDS-3 and GDS-4. More specifically, GFAI recommends, as an alternative to its other proposal, that the Commission adopt the AIUs' proposal to apply AmerenIP's current GDS-3 and GDS-4 eligibility requirements to AmerenCILCO and AmerenCIPS, albeit with the highest daily average usage used to determine tariff Availability measured only from December through March. (GFAI Ex. 1.0G, pp. 4-5.)

Hence, the Commission should accept the AIUs' proposal to adopt a 1000 therm highest daily average usage cutoff between GDS-3 and GDS-4 and reject the GFAI's proposal to utilize an inconsistent annual usage measure for this purpose.

b. *Large Customer Rate for Non-CILCO GDS-4*

AmerenCILCO currently serves gas customers with annual usage in excess of 2,000,000 therms under rate class GDS-6. The AIUs propose to eliminate AmerenCILCO's GDS-6 as a stand-alone tariff and transfer AmerenCILCO's GDS-6 customers to rate class GDS-4 and provide special tariff provisions for these large customers. (Ameren Ex. 17.0G Rev. (Millburg Dir.), p. 21.) As described in Section VI.B.3.c, Staff witness Harden recommended approval of the AIUs' proposal to eliminate AmerenCILCO's GDS-6 as a stand-alone tariff and the special large customer provisions under AmerenCILCO's GDS-4 rates. (ICC Staff Ex. 9.0 (Harden Dir.), pp. 36-37; ICC Staff Ex. 22.0 (Harden Reb.), p. 2.)

AmerenIP and AmerenCIPS do not have a similar rate class GDS-6. For these utilities, the large customers already are served in GDS-4. (Ameren Ex. 17.0G Rev., p. 21.) Accordingly, the AIUs do not need to move customers from GDS-6 for these utilities. Hence, the AIUs did not need to provide special provisions in GDS-4 rates to avoid rate shock. (See id.)

The only reason that the AIUs proposed revisions to the AmerenCILCO GDS-4 tariff was to ease the transition for AmerenCILCO utilities GDS-6 customers to GDS-4 service. (Ameren Ex. 58.0 2d Rev. (Millburg Sur.), p. 8.) Because neither AmerenCIPS nor AmerenIP have a GDS-6 rate, introducing a large customer provisions to the AmerenCIPS and AmerenIP proposed GDS-4 tariffs is unnecessary and would introduce an unnecessary level of complexity. (Id.) AmerenCILCO is proposing to include the price step in its GDS-4 tariff simply to promote stability for the existing customers served under its GDS-6 tariff. (Id.)

Ms. Harden believes that, as part of the next AIU rate cases, AmerenIP and AmerenCIPS should match AmerenCILCO's special rate design provisions for their customers with annual usage greater than 2,000,000 therms. (ICC Staff Ex. 22.0, p. 3.) Ms. Harden does not recommend the Commission require AmerenIP and AmerenCIPS to add special these provisions as part of these rate cases. (Id.) She also recognizes that AmerenIP and AmerenCIPS have not "assembled the relevant data to evaluate a similar rate design" for those utilities. (Id., p. 5, lines 91-92.) As a result, Ms. Harden only recommends that the AIUs "should be ordered to assemble the relevant data for their next rate case." (Id., lines 99-101.) Ms. Harden states that with this data, AmerenIP and AmerenCIPS should be able to evaluate a similar rate design for their large customers. (Id.)

While Ms. Harden correctly cites the AIUs' goal in achieving tariff uniformity among the three companies wherever possible, she ignores that the introduction of Staff's proposed tariff revisions would inject an unneeded level of complexity into the AmerenCIPS and AmerenIP tariffs. (Ameren Ex. 58.0 Rev., p. 7.) AmerenCILCO's special provisions for large customers are one of the few instances where other factors take precedence over the desire for tariff uniformity. (Id.)

The AIUs agree with Ms. Harden's recommendation that, in the time between these rate cases and the next rate cases, the AIUs should assemble data associated with AmerenIP's and AmerenCIPS' GDS-4 customers with annual consumption over 2,000,000 therms to evaluate whether AmerenCIPS and AmerenIP should implement special GDS-4 rate provisions for those customers. (Id.) While the AIUs are only proposing these tariff provisions for AmerenCILCO in these rate cases, the AIUs agree that assembling this data may help provide support to the AIUs' gas tariff design in the next rate case. (Ameren Ex. 58.0 2d Rev., p. 9.)

Thus, the Commission should: (a) accept the elimination of AmerenCILCO's GDS-6; (b) accept the new tariff provisions AmerenCILCO GDS-4 gas customers with annual consumption over 2,000,000 therms; (c) accept Staff's recommendation that the AIUs be required to collect the relevant data associated with the AmerenCIPS and AmerenIP GDS-4 gas customers with annual consumption over 2,000,000 therms for use in the rate design analysis in the next rate case; and (d) accept the AIUs proposal to not include special provisions for the large GDS-4 customers of AmerenCIPS and AmerenIP in these rate cases because the necessary data has not yet been assembled.

c. *Seasonal Prices for all GDS Rates*

GFAI recommends that all delivery charges, excluding monthly fixed charges, reflect seasonal prices. (GFAI Ex. 1.0G (Adkisson Dir.), p. 6.) GFAI's reasoning behind that recommendation is its misplaced belief that the AIUs' distribution system capacity only is designed to carry the utilities' overall winter peak usage. (Id.) In actuality, the fact is that the

AIUs design their systems to support the peak needs of their customers, regardless of the time of year in which they occur. (Ameren Ex. 48.0 Rev. (Millburg Reb.), p. 14.) If the sole design criteria were based on system peak usage during the winter months, then off-peak gas users (like GFAI's members) would have insufficiently sized facilities to support their operations, since their winter gas usage is either minimal or non-existent. (Id.) GFAI's recommendation is inconsistent with the principles of system design and the recovery of system investment costs. (Id.)

GDS-5 is the AIUs' Seasonal Gas Delivery Tariff service, and it is the tariff most applicable to GFAI's members. (Id.) GDS-5 reflects the different impacts these seasonal-use customers have on costs associated with gas delivery. (Id.) The purpose of the GDS-5 tariff is to promote system reliability by discouraging gas use by individual customers whose operation on days when space heating demands increase would cause reliability issues.[54] (Ameren Ex. 58.0 2d Rev., p. 13.) Usage by GDS-3 and GDS-4 customers during periods when peak space heating load occurs can have a profoundly negative impact on system reliability. (Id.) As a result, GDS-5 is designed to provide incentives to GDS-3 and GDS-4 customers whose processes enable them to avoid operating during periods of heating loads. (Id.) It is true that GDS-2 customers might not financially benefit from selecting to be billed under the optional GDS-5 tariffs. But, this does not inappropriately exclude those customers from the optional GDS-5 tariffs because the usage of small GDS-2 customers typically does not affect the reliability of the distribution systems that serve them when space heating load occurs. (Id.)

[54] GFAI witness Adkisson mistakenly asserts that that the purpose of the GDS-5 seasonal rate is to increase system utilization by encouraging off-peak use. (GFAI Ex. 2.0G, pp. 2-4) GDS-5 is intended primarily to enhance system reliability. (Ameren Ex. 58.0 2d Rev., pp. 14-15.)

Accordingly, the Commission should reject GFAI's proposal to implement seasonal pricing provisions be established for all delivery charges.

d. *Transportation Tariff (Rider T)*

As discussed in Section VI.C.2.b, the AIUs' natural gas distribution service can be split into two categories: sales service and transportation service. In essence, sales customers purchase gas from the AIUs while transportation customers purchase gas from a third party. In either case, the AIUs deliver the natural gas to the customers. Transportation customers take service from the AIUs under Rider T.

In the last rate cases, specific tariff provisions were adopted for small volume transportation customers served under the AIUs GDS-2 and GDS-3 rate classes, including seasonal customers taking service under GDS-5. The Commission, for example, determined that the customers should be able to call on 10 times their maximum daily contract quantity ("MDCQ").[55] Docket, 07-0585 (cons.), Final Order (Sept. 24, 2008), pp. 312-14. These new tariff provisions went into effect in October 2008 (only 8 months prior to the initiation of these proceedings) including only one heating season. (Ameren Ex. 22.0G (Dothage Dir.), p. 9.) The AIUs do not have enough operating data under the new tariff provisions to provide an in-depth understanding as to rate impacts or usage patterns to make an informed decision that would warrant any material changes to the balancing or metering requirements. (Id.)

[55] The multiple MDCQ is commonly referred to as the "days of bank" or the "size of the bank."

The AIUs provide a banking service to their transportation customers.[56] (See, e.g., AmerenCIPS's Rider T - Gas Service Schedule Ill. C.C. No. 20, 2nd Revised Sheet Nos. 25; AmerenIP's Rider T - Gas Service Schedule Ill. C.C. No. 37, 1st Revised Sheet Nos. 25; AmerenCILCO's Rider T - Gas Service Schedule Ill. C.C. No. 19, 1st Revised Sheet Nos. 25.) Under this service, if a transportation customer delivers more gas in a day to the AIUs than the customer uses for that day, then the AIUs will hold – or "bank" – that excess gas until it is needed by the customer. (Id.) In this way, customers can bank an amount of gas equal to up to 10 times its maximum daily contract quantity ("MDCQ"). (Id.) If a customer has a positive balance in its "bank" account, then the customer can call on its bank by using more gas in a day than it delivers in that day.[57] (Id.) In that situation, the AIUs would make up the difference by using their storage, line pack, or imports from off-system resources. The costs of providing the banking service are recovered through base rates as part of the distribution service. (See, e.g., Sec. VI.C.2.b., supra.)

The AIUs have not recommended any operational changes to their transportation services. Staff, however, makes two recommendations with regard to the bank size. First, Staff recommends that the bank service be unbundled base rates as part of the AIUs next rate cases and that the bank service be provided on a subscription service. (See, e.g., ICC Staff Ex. 27.0R (Sackett Reb.), pp. 2, 7.) Second, Staff recommends that the Commission determine the bank

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[56] To be clear, the AIUs' banking service is not a storage service. Although those services have some similar aspects, the AIUs do not store gas on behalf of the transportation customers. Rather, the banking service is more akin to a tool that is made available to transportation customers to aid in imbalance management.

[57] There are a number of operational details that affect the amount of gas that can be credited to or debited from a customer's "bank" account in a day. But, those details are beyond the scope of this section of the brief and are not contested in these cases.

size in the next rate cases based on specified methodology. (See, e.g., id., pp. 14, 34-35.) The AIUs agree that these issues should be addressed in the next AIU rate cases. To that end, the AIUs have agreed to participate in the public workshops proposed by Staff witness Sackett. For the reasons set out below, the Commission should not implement any changes to the Rider T banking program as part of these rate cases.

(1) Unbundling Banking Rights

There is general agreement that the AIUs should address the unbundling of the Rider T banking service in their next rate cases after a public workshop process. Staff witness Sackett recommends that the AIUs participate in a public workshop process to determine equitable methods for unbundling the Rider T banking service.[58] He, moreover, recommends that any tariff revisions resulting from the workshop process be addressed as part of the next rate cases.[59] CNG witness Kawczynski also proposes that the AIUs' participate in a workshop that would address the unbundling of the banking service in the AIUs' next rate cases. (CNE-Gas Ex. 2.0 (Kaczynski Reb.), p. 24.) AIU witness Dothage expressed the AIUs willingness and commitment to participating in the workshops proposed by Mr. Sackett. (Ameren Ex. 64.0

[58] In his direct testimony, Staff witness Sackett recommended that the issue of unbundling the AIUs' storage banks should be addressed in a workshop before the next rate case. (See, e.g., ICC Staff Ex. 27.0R, p. 7 ("I recommend that all of these changes be made during a workshop process that would occur before the Companies file their next rate cases.").) In his rebuttal testimony, Mr. Sackett reiterated his recommendation that the AIUs unbundle their banking service in the next rate cases. (Id., pp. 2-3 ("… Require the Companies to unbundle Rider T's bank from base rates in the *next* rate case and work with Staff and Intervenors in the interim through a workshop process to determine equitable methods of allocating both storage capacity and costs."); see also Ameren Ex. 64.0 Rev., p. 12 ("In his rebuttal testimony, Mr. Sackett provides more insight as to what he considers to be a the necessary steps to reach an unbundled bank. But, he does not change his ultimate recommendation that these issues be addressed in a workshop before the AIUs' next rate cases.")

[59] See previous footnote.

(Rev.) (Dothage Sur.), pp. 13-18.) In fact, AIU witness Mr. Dothage testified that the proposed workshops would be beneficial because they would "enable interested parties to get together and develop an appropriate unbundled Rider T bank service with an appropriate subscription and implementation process." (Id., p. 13, lines 266-67.)

There also is general agreement that transportation customers should be able to determine the size of bank that they desire and are willing to pay for. Staff witness Sackett, for instance, recommends that the Rider T bank service be unbundled in a way that would allow customers to subscribe to the level of service desired. (ICC Staff Ex. 14.0 (Sackett Dir.), p. 18; ICC Staff Ex. 27.0R (Sackett Reb.), p. 14.) AIU witness Dothage agrees. He testified that if the unbundling were structured properly, the transportation "customer would be the one to decide what level of bank to subscribe to based on the cost of the service instead of having to accept what level of bank service is negotiated by the parties participating in rate proceedings." (Ameren Ex. 64.0 Rev., p. 12, lines 246-49.) The workshop process will show whether transportation customers are actually interested in an unbundled Rider T banking service. (Id.)

No party to this proceeding has proposed to unbundle Rider T banking service as part of these rate cases and the record in these rate cases does not support such a change. The AIUs are not opposed to a properly structured workshop or to addressing unbundling in their next rate cases. The Commission should accept these recommendations and create a workshop process in which the AIUs, Staff, transportation customers and other interested parties can address the unbundling of the Rider T banking service. The Commission should, however, refrain from mandating specific tariff or rate structures or otherwise inhibit the workshop process. The workshop process will be best served by letting the participants determine the nature and scope of the discussions. An unfettered workshop process, for example, will permit the participants to identify the unbundling structures that best serve the AIUs and the customers. If they wish, any interested party can present alternative positions in the next rate cases.

(2) Size of Rider T Bank

(a) *The Rider T Banks Should Be Addressed In A Workshop Forum*

The Commission established the 10-day bank size in the last rate cases. (Docket, 07-0585 (cons.), Final Order (Sept. 24, 2008), pp. 312-14. No party has proposed any changes to the bank size for these proceedings. Staff proposes to expand the Rider T bank sizes in the next rate cases after the workshops discussed above.[60] The AIUs have agreed to participate in those proposed workshops. The Commission should leave it to the workshop participants to determine the unbundled structure including the bank sizes available to the customers.

Staff witness Sackett discusses at length the methodologies used by Peoples Gas, North Shore Gas, and Nicor Gas for determining the size of the bank available to those utilities' transportation customers.[61] (See, e.g., ICC Staff Ex. 14.0 (Sackett Dir.), pp. 22-24.) The application of these models to the AIUs would result in an increase in the bank size from the

[60] In his direct testimony, Staff witness Sackett recommended that the issue of bank size be addressed in a workshop before the next rate case. (See, e.g., ICC Staff Ex. 27.0R, p. 7 ("First, I recommended that AIU be required to equitably allocate storage *capacity*. … I recommended that all of these changes be made during a workshop process that would occur before the Companies file their next rate cases." (Emphasis in original).) In his rebuttal testimony, Mr. Sackett reiterated his recommendation that the issue of bank size be addressed in a workshop before the next rate case. (Id., p. 27 ("My proposal is not to make any changes at this time, but rather, develop a workable plan before Ameren's next rate case.").)

[61] For clarity, the methodology used by Peoples Gas and North Shore Gas is called the "Peoples Method" and the methodology used by Nicor Gas is called the "Nicor Method"

existing 10 times MDCQ to between 11 and 37 times MDCQ. (Id.) As described in the previous section, the AIUs and Staff believe that an important part of the unbundling of the Rider T banking service would be to allow the transportation customers to determine the size of the bank that they desire and are willing to pay for. Mr. Dothage, for example, testified that:

> The fundamental premise of unbundling any service is to allow the customer to choose the services it desires and the level of service desired. In order to make an informed decision or election, the customer should know the cost of the service upfront. In the case of unbundling transportation banks, a customer should start with the choice of a zero bank level until it knows what the cost of electing a certain level of bank is. A reasonable approach to follow in the workshop process would be to first identify the available resources needed to support the bank service, determine the price/cost of the resources, make the service available at a specified price and then let the customer elect a certain level of bank service.

(Ameren Ex. 64.0 Rev., pp. 11-12, lines 250-58.) It would be inconsistent to allocate a fixed amount of capacity to these customers and permit them to choose the amount of capacity they desire.

Allowing customers to choose the desired level of banking capacity is better for customers and inconsistent with the restrictive boundaries of the Nicor and the Peoples Methods. (Id., p. 14.) Any changes to the existing level of Rider T banks (which is currently a uniform 10 times the transportation customers' MDCQ for all three of the AIUs) should be the result of AIUs' customers' actual elections of individual bank capacity levels as a result of the unbundling that the parties will explore in the workshops that will before the next rate case. (Id.) Rather than have Staff, CNG, AIUs, or the Commission establish a bank level for the customer to "take," the customers themselves should subscribe to the level of banking services they believe fits their gas and supply needs. (Id., p. at 15.) The workshop process would provide a reasonable forum for the interested parties to work toward developing a workable unbundled transportation bank service. (Id.)

The Commission should not address the merits and applicability of the Nicor and Peoples Methods in this case. Likewise, the Commission should not limit the workshop discussion to the Nicor or Peoples Methods. The workshop forum proposed by Staff and CNG is the proper place for these models and other possible capacity allocation methodologies to be evaluated for the first time in the context of an unbundled Rider T banking service. (Id., p. 14.) The Commission should let the workshop process address the issue directly. (Id., p. 15.)

(b) *The Peoples and Nicor Methods Produce Meaningless Results When Applied to the AIUs and Should Be Rejected*

Staff suggests that the Peoples and Nicor Methods should be used to guide the determination of the appropriate size of the Rider T banks in the workshop process. (See ICC Staff Ex. 14.0 (Sackett Dir.), p. 22.) The Commission, however, should not require the AIUs to follow those Methods. They do not produce reasonable results when applied to the AIUs. (AIU Ex. 64.0 Rev. (Dothage Sur.), p. 16.) In fact, those Methods have material defects that may not have been identified in previous Commission proceedings. (Id.) Staff witness Sackett states that those methods have been approved for use by those utilities so they must be reasonable for use by the AIUs. (ICC Staff Ex. 27.0R (Sackett Reb.), p. 21.) The Commission should not require the AIUs to follow either of these Models simply because they have been previously used by other utilities, without first factually reviewing the results of their application to the AIUs.

The Peoples Method divides the utility's total storage capacity by the utility's system's total deliverability on a peak day. (ICC Staff Ex. 14.0, p. 22.) The Nicor Method divides the on-system storage capacity by the system's total deliverability on a peak design day. (Id.) Both methods purport to arrive at a number of days of peak deliverability. (Id., p. 24, Table 4.)

The defect of both Methods is that there is no relationship between the numerator of the equation (storage capacity) and the denominator (peak day deliverability of the system). (AIU Ex. 64.0 Rev., p. 15.) The Methods are merely mathematical calculations that do not speak to the operational issues or system constraints. (Ameren Ex. 44.0 (Dothage Reb.), p. 21.) The Methods do not show any real relationship between the seasonal working inventory of the storage field and the system peak day deliverability. (Id., p. 22.) One is an inventory volume over the entire five month winter season, while the other is a daily deliverability volume. (Id.) Dividing the two produces a mathematical result, but that result does not have a rational meaning in the real world of physical deliverability and capacity. (Id.) As Mr. Dothage testified on the stand during cross-examination: "Both models make a division, mathematical computation, and they purport to arrive at a number of days, but it could just as easy be a number of shoes because there's no relationship between the two numbers, the numerator, and the denominator." (Tr. 834, lines 9-13.)

The fallacy of the Methods is best explained by applying the Nicor Method to AmerenCILCO as an example set out in the following formulas:

<u>Nicor Method</u>

Days of Deliverability = (on system storage capacity) / (peak day deliverability)

Nicor Method applied to AmerenCILCO
Days of Deliverability = (8,172,473 MMBtu) / 339,297 MMBtu = 24

(See ICC Staff Ex. 14.0, p. 24, Table 4.) The mathematic calculation dividing 8,172,473 MMBtu of on-system storage capacity by 339,297 MMBtu of peak day deliverability results in a value near 24. The Nicor Method would say that this represents 24 Days of Deliverability for Ameren CILCO. The result of that calculation does not mean that the AmerenCILCO's total on-system seasonal storage capacity of 8,172,473 MMBtu could serve AmerenCILCO's sales customers with 339,297 MMBtu for 24 days. (Ameren Ex. 64.0 Rev., p. 15.) The fact is that AmerenCILCO storage fields can only deliver a combined 190,000 MMBtu on a peak day. (Id.) In operational terms, therefore, the fields could not even serve the sales customers' peak load under Staff's calculations even for one day – much less the 24 days that the Nicor Method would suggest. (Id.) The Peoples Method suffers from the same fatal flaw. There is no relationship between the seasonal storage working capacity and the peak day deliverability of the system. (Id.)

Staff's suggestion that the Commission consider the Nicor and Peoples Models in the future might result from a failure to appreciate the difference between a storage field's peak day deliverability and its total storage capacity. A storage field cannot release 100% of the gas in storage on the peak day. For instance, AmerenCILCO's on-system storage has a total capacity of 8,172,473 MMBtu, but AmerenCILCO can only withdraw 190,000 MMBtu from those fields on a peak day. While there is some relationship between the peak day withdrawal capabilities and total system peak day deliverability, there is no relationship between the total storage capacity and total system peak day deliverability. (Tr. 833.)

The Nicor and Peoples methods do not produce reasonable (much less meaningful) results when applied to the AIUs. The Commission should allow the customers to choose for themselves the size of bank that they require and are willing to pay for. More particularly, the Commission should allow the agreed upon workshop process to determine the structure an unbundled Rider T where the customers (not the Staff, the AIUs or the Commission) choose the bank size after they know the price for the service (based on the AIUs' cost of providing the service). The Commission should not predetermine that the workshop process result by requiring in these rate cases the application of the Nicor or Peoples method.

(c) *The Current Rider T Banks Methods Provide Equitable Results*

The Commission approved the 10-day bank capacity in the AIUs' previous rate cases. Docket 07-0585 (cons.), Final Order (Sept. 24, 2008), pp. 312-14; (Ameren Ex. 64.0 Rev. (Dothage Sur.), p. 18.) This maximum bank level is applicable on a uniform basis across all three AIUs and provides continuity of Rider T tariff provisions for transportation customers and their marketers. (Ameren Ex. 64.0 Rev., p. 18.) The 10-day bank capacity resulted from the blending the banking levels on the AmerenCIPS, AmerenCILCO, and AmerenIP systems that existed prior to the AIUs' 2007 rate case filings. (Id.) With sale customers' conversions to transportation service occurring in 2009, the AIUs' total bank levels have more than tripled from the levels that existed prior to the AIUs' 2007 rate cases. The existing 10-day bank allocation to transportation customers is fair and equitable. (Id.)

Basing the unbundled bank size using either of the Nicor or Peoples Methods will have a negative impact on the system sales customers because any additional seasonal storage capacity that is allocated to support additional days of banking for the transportation customers, ultimately will be seasonal storage capacity taken away from the system sales customers. (Ameren Ex. 44.0 (Dothage Reb.), p. 23.) If the AIUs must provide additional days of banking rights to the transportation customers, the AIUs will have to acquire new seasonal storage capacity for their sales customers to replace the storage allocated to the increased banking service. (Id.) The major risk and harm to the sales customers is that new seasonal storage capacity may not be available in the marketplace. (Id.) But, even if it is available, the capacity likely would be at a much higher cost than the existing storage capacity. (Id.) This could cost financial harm to the AIUs' 821,300 sales customers, for the benefit of the AIUs' 481 transportation customers. (Id.)

Expanding the bank size should be considered as part of an integrated unbundling workshop. Simply expanding the bank size (by applying the Peoples or Nicor Methods) would result in an inappropriate allocation of valuable storage resources away from serving system sales customers (the majority of which are high-priority residential heating load customers) and an allocation of these storage resources to transportation customers and their marketers. (Id.) All of the AIUs' storage resources, company-owned and leased, as well as the firm transportation capacity contracted for on the interstate pipelines are required for the AIUs to serve system sales customers and to provide the balancing and bank flexibility to transportation customers as required under the tariff terms and conditions of Rider T. (Id., p. 17.)

In order to unbundle appropriately the Rider T banking service, a portion of each gas supply system resource would need to be carved out and packaged in a separately priced banking service.[62] (Id., pp. 17-18.) It would be inappropriate and unfair to carve out storage resources to support and unbundled banking for transportation customers as would occur if the Commission required the AIUs to use the Nicor or Peoples Methods in the unbundling. (Id.)

Thus, the Commission should establish a workshop process where the parties can endeavor to establish a reasonable approach to unbundling the transportation banks and costs and should allow customers to choose the services that they need at a cost known to them in advance. The Commission should not prejudge the unbundling process and require the AIUs to establish the banking rights using either the Nicor Method or Peoples Method.

e. *Other*

2. Electric

a. *Rate Moderation/Mitigation Approaches*

The AIUs, Staff, and the IIEC were the only parties to present rate moderation/mitigation testimony in this case. All rate design proposals in this case are, in part, cost-based and, accordingly, utilize an embedded cost of service study as a starting point. Arguments relating to the merits of the various ECOSS methodologies employed by the parties are discussed in the section entitled "Cost of Service/Revenue Allocation," at Section VI, supra.

In order to establish a rate design, all parties utilized the results of their respective ECOSS methodologies and applied mitigation strategies to underlying cost indicators. Those mitigation strategies serve an important role in promoting rate continuity and rate stability

[62] This would also result in a mixing of costs that are allocated to and recovered from customers in rate cases with costs that are allocated to and recovered from customers in Purchased Gas Adjustment ("PGA") filings. (Ameren Ex. 44.0, p. 18.)

while considering potential bill impacts that could result as rates are moved toward a cost-basis. (See Ameren Ex. 16.0E 2nd Rev., p. 5)

Staff proposes to constrain rate increases to 150% of the overall average, including Distribution Tax. (See generally Ameren Ex. 55.1, for a comparison of the rate design approaches of Staff, IIEC, and the AIUs.) That proposal, however, puts a disproportionate burden on classes DS-3 and DS-4, and, consequently, widens the gap between DS-3 and DS-4 on a dollar per kW demand charge basis. (Ameren Ex. 55.0 Rev., p. 2.) Even if the Commission adjusts the revenue requirement downward due to proposals by the parties, the relative differences and relative magnitude of the difference remains the same. (Id.) The disproportionate burden created for DS-3 and DS-4 under this approach moves away from the stated goal of cost-based rates and mitigation of bill impact. (Id.) Accordingly, the Commission should reject the Staff's proposal to include the distribution tax in the rate mitigation method.

IIEC proposes to limit increases to the overall average plus 25 percentage points for each class or subclass. (Ameren Ex. 55.1.) The problem with IIEC's proposal is that it defines "subclasses" based on the customer's supply voltage and customers often use more than one voltage. (Ameren Ex. 55.0 Rev., p. 5.) Indeed, many customers take service supplied at a higher voltage than that delivered and metered. (Id.) The Commission should reject the IIEC's proposed rate mitigation method because it is lacking in both detail and guidance.

On the other hand, the AIUs have proposed to mitigate the rate changes to customer classes due to bill impact concerns. (Ameren Ex. 55.0 Rev., p. 2.) The AIUs proposed revenue allocation approach provides a better balance between movement toward cost-based rates and mitigating bill impact. (Id.) The AIUs propose to limit the increases for Rate Classes DS-1 through DS-4 to 125% of the system average increase, excluding DS-5 Lighting and Distribution Tax. (See Ameren Ex. 55.1.) The Commission should adopt the AIUs' proposed revenue allocation approach because it provides a better balance between movement toward cost-based rates and mitigating bill impacts. (Ameren Ex. 55.0 Rev., p. 2.).

Contrary to Staff and IIEC's approaches, the AIUs' rate design mitigation approach properly excludes the distribution tax. (Id.) Because the distribution tax is assessed to the utility on a kWh or energy basis, it should be assessed to customers in the same manner, without effectuating cross-subsidies that would otherwise invariably be created by rate mitigation strategies. As Staff witness Mr. Lazare acknowledged, the ultimate effect of "mitigating" cost assignments by including the impact of the distribution tax assessed to utilities would be subsidized rates. (Tr. 145-48.) Further, Mr. Lazare acknowledged that using AmerenCILCO as an example, DS-4, DS-3, and DS-2 customers would be receiving a subsidy on a class total revenues basis, inclusive of a portion of the distribution tax associated revenue requirement. (Id., 148-149.) It therefore can be concluded by the process of elimination that the incremental effect of including the distribution tax in a rate mitigation approach serves to increase the subsidy burden imposed upon residential (DS-1) and lighting customers (DS-5). It is intrinsically unfair to hold residential and lighting customers responsible for tax liabilities that would not exist but for the kWh usage of larger customers.

Additionally, IIEC's proposed rate design not only applies a mitigation approach to costs inclusive of the distribution tax, but also allocates the costs by plant as part of its ECOSS analysis. The AIUs address the short-comings and inequities of this approach more thoroughly in the section entitled "Overall Rate Design," infra.

For the foregoing reasons, the AIUs believe that their proposed rate design and mitigation strategies are sound and should be approved in this docket.

b. *Overall Rate Design*

The AIUs' overall rate design utilizes a cost basis as a starting point, applies a rate moderation/mitigation approach to the cost basis, and adjusts rate among classifications in an attempt to comport with the stated goals of the AIUs, stakeholders, and the Commission in the last rate proceeding. (See generally Ameren Ex. 16.0E 2nd Rev., pp. 4-43.)

While changes to DS-1 and DS-2 were not contested issues in this proceeding, the changes to those rate structures are an important component of the AIUs' overall rate design. Specifically, the AIUs sought to conform their rate design to the Commission's Final Order in the previous rate case with respect to DS-1/BGS-1 space heat customers. (Id., pp. 19-29.) The AIUs also sought to move closer to rate uniformity among the Companies. (Id.) To do so, the AIUs modified their DS-1 rates, in order to move towards a "Straight Fixed Variable" or "SFV" approach. Under the proposed rates, the AIUs will recover approximately 39% of allocated delivery service charges through the customer and meter charges, an increase from the current rates. (Id., p. 24.) The change to the BGS-1 supply rate structure compliments this approach and refines the AIUs' approach to rates for customers using electric space heating. The changes to BGS-1 are complimentary to the changes to DS-1, and are described in Section VII.2.f.), "Variable Tail Block Rates – BGS-1," infra. (See also Ameren Ex. 16.0(E) 2nd Rev., pp. 25.29.) Rates for classes DS-2/BGS-2 were also realigned in this manner. (See id., pp. 29-33.)

The AIUs also propose changes to general service (DS-3) and large general service (DS-4) customers. (See generally Ameren Ex. 16.0E 2nd Rev., pp. 33-43. See also Ameren Ex. 16.7E and Ameren Ex. 16.10E, for an analysis of bill impacts for DS-3 and DS-4 customers.) The rate design for these classes remains a contested issue. (See Sections VII.C.2.c., VII.C.2.d., VII.C.2.g., and VII.C.2.h, infra.) Similarly, rate design for lighting customers (DS-5) remains a contested issue. (See Section VII.C.2.e., infra; Ameren Ex. 16.0 2nd Rev., pp. 43-46.)

As noted above, Staff, IIEC, and the AIUs all take similar approaches to rate design. Using an ECOSS study as the starting point, rates were designed by the respective parties, with costs as a primary driver. Ultimately, however, rates were tempered by mitigation strategies, with all parties cognizant of rate impact implications.

Only Staff and the AIUs offered testimony regarding how rates should be conformed to the final revenue requirement. (See Staff Ex. 7.0, p. 41; Ameren Ex. 40.0 2nd Rev., pp. 15-17). Conforming rate design to final revenue requirement is an essential step in the ratemaking process, and is a critical component of the AIUs' overall rate design recommendations. Although the case begins with the revenue requirements that are filed on behalf of the companies, there is always the expectation that the final outcome of the case will inevitably be a revenue requirement that is lower than the initial request. In fact, after a review of the testimony, the AIUs have accepted and modified their initial proposal in a manner that ultimately reduces the revenue requirement below their first request. As a result, the conformance of the final rates to the adjudicated revenue requirement is an essential task in this case.

Each of the parties takes a different approach to rate design. Staff prefers to lower all DS components to achieve the final revenue requirement allocated to a class. (ICC Staff Ex. 21.0, p. 20.) In order to accomplish that goal, Staff recommends adjusting the uniform rates among the AIUs – Customer, Meter, Transformation, and Reactive Demand Charges – on a combined AIU basis, and then adjusting the remaining rate components by an across-the-board amount to achieve the desired revenue target. (Id.) Staff dismisses the AIUs' proposed rate adjustment methodology, for no other reason than because Staff deems its methodology to be the simplest. (Id.)

While Staff's across-the-board approach is indeed one easy way to set rates, it is no easier than using the AIUs' cost-based approach. (Ameren Ex. 55.0 Rev., p. 7.) Under the AIUs' approach, final rates are adjusted to meet certain rate design objectives, rather than an oversimplified across-the-board approach. (Id.) The AIUs' proposal provides a better balance between movement toward cost-based rates and mitigating bill impacts. (Id., p 3.) Additionally, this approach has been used by the Commission in the past. (See, e.g., Docket No. 91-0335, p. 70-72; Docket No. 93-0183, 90-107; Docket No. 99-0120/99-0134 p. 64.)

Staff's approach misses an opportunity to address subsidy elimination, rate continuity, and bill impact concerns. (Id.) It also misses an opportunity to better address concerns raised by various parties in this case. (Id.) Staff's approach exacerbates a problematic divergence between DS-3 and DS-4 delivery rates and, as such, fails to address this important concern. This problem is discussed more thoroughly in the section entitled "Distribution Delivery Charges – DS-3 and DS-4," infra. Because Staff's oversimplified approach strays from the goals of cost-based ratemaking and mitigating bill impacts, and the AIUs' approach embraces those goals, the AIUs' rate design approach should be approved by the Commission in this docket.

c. *Recovery of Electric Distribution Tax/Public Utilities Revenue Act Tax*

The AIUs propose a method of accounting for and recovering the Distribution Tax. The Distribution Tax is a cost that is energy related, yet Rates DS-3 and DS-4 do not currently contain any energy-related charges. (Ameren Ex. 16.0E 2nd Rev., p. 13.) Staff proposed that the AIUs should, instead of recovering these costs in a rider, recover those costs in base rates through the kWh-based Distribution Delivery Charge from DS-1, DS-2 and DS-5 classes, and further proposed that that a kWh charge should be created that would apply to DS-3 and DS-4 classes. (Staff Ex. 7.0, p. 5.) While there is substantial merit in the rider approach, the AIUs accept Staff's recommendation. (Ameren Ex. 40.0 2nd Rev., p. 3.)

IIEC, on the other hand, takes issue with the Distribution Tax recovery proposals of the AIUs and Staff, noting that some customers will receive significant increases in delivery service costs, and as a result, suggests that there will be an undue impact on industrial customers. (IIEC Ex. 1.0, p. 27.)

While it may be true that certain DS-4 customers will see a large percentage increase in their delivery service bill, it is also true that those customers' increases on a total bill basis are among the lowest of any non-lighting class. (Ameren Ex. 40.0 Rev., p. 24.) When viewed on a total bill basis, the percentage increases compare favorably to increases proposed for other classes. (Id.; Ameren Ex. 40.2; Ameren Ex. 40.3.) Even assuming delivery service increases to customers of 350%, the bill increase is merely 2-3%. (Id.)

IIEC proposes that distribution taxes continue to be allocated among rate classes according to their share in plant service. (IIEC Ex. 1.0, p. 24.) As part of that argument, it states that "[i]n each round of delivery service rate cases since enactment of the 1997 law, the various Ameren companies have proposed, and the Commission has approved, the cost study allocation of the PURA tax on the same basis as the overall distribution plant is allocated." (Id., p. 17.) However, the Commission's longstanding principle has been to develop rates on the basis of cost causation principles. (ICC Staff Ex. 21.0, p. 3.) Here, movement to a cost-based approach is the most equitable and efficient approach. (Id.)

IIEC claims that the largest driver of any utility's PURA Tax responsibility is its level of invested capital used to develop the tiered changes charges in the 1997 deregulation law, and states that the current levels of tax is a primary function of the past levels of past assets. However, as Staff notes, the Illinois General Assembly made a conscious decision to change the way the distribution tax is determined by replacing a tax based on invested capital with a tax determined by usage. (ICC Staff Ex. 21.0, p. 4; 35 ILCS 620/1a, P.A. 90-561, eff. 1-1-98.)

Thus, sales, rather than plant investment, now determine how much in distribution taxes the utilities pay. (ICC Staff Ex. 21.0, p.5.) Under the current legislation, changes in the amount of plant in service for utility do not affect the amount of distribution tax paid. (Id.) If the level of plant were to double or to decline by half, that specific change would have no impact on the utility's distribution tax. In contrast, the level of deliveries by electric utilities does directly affect distribution taxes. (Id.) If a utility's level of deliveries goes up relative to the other electric utilities in Illinois, its share of distribution taxes will increase. (Id.) If its relative levels of deliveries decline, the utility's share of the distribution tax total will fall. (Id.) Since the level of deliveries, not plant in service, determines the amounts of distribution taxes for individual utilities each year, usage should be the basis for allocating these costs. (Id.) Accordingly, the AIUs proposal, rather than IIEC's, should be accepted by the Commission.

d. *Distribution Delivery Charges: DS-3 and DS-4*

The Distribution Delivery Charge for customers with demands of 150 kW and over are currently demand-based and voltage-differentiated. (Ameren Ex. 16.0 (2nd Rev.) (Jones Dir.) p. 39.) Customers served at lower voltages require additional investment in distribution facilities as compared to customers served at higher voltages. (Id.) As a result, voltage differentiated pricing reflects the costs incurred to serve customers, and is higher for low voltage customers and lower for high voltage customers. (Id.)

The AIUs propose Distribution Delivery Charges that were developed using an approach similar to that used to establish prices for the same components in Docket Nos. 06-0070 – 06-0072 (cons.). (Ameren Ex. 16.0 (2nd Rev.) (Jones Dir.) p. 39.) Here, the demand-related costs for DS-3 and DS-4 were combined and divided by the combined voltage differentiated demands. (Id.)

The AIUs' revenue allocation approach should be used to determine Distribution Delivery Charge for DS-3 and DS-4, as it establishes more consistent bill impacts among customer classes. (Ameren Ex. 40.0 Rev. (Jones Reb.) p. 5.) The AIUs' approach provides for relatively moderate differentiation between classes when compared to Staff's approach. (Id.) Under Staff's approach, AmerenIP and AmerenCILCO DS-3 customers take on a greater burden. (Id.) Additionally, Staff's approach unnecessarily shifts total bill impacts in the opposite direction for DS-4 customers. (Id.) While Staff's revenue allocation approach provides marginal relief to the DS-4 class for each of the AIUs, it contributes to more severe DS-3 total bill impacts for AmerenIP and AmerenCILCO.

That issue is important when considering that DS-3 customers with larger demands, or DS-4 customers with smaller demands, may reclassify from DS-3 to DS-4, and vice versa. (Id.)

Under Staff's proposal, a customer reclassifying from DS-4 to DS-3 may experience a rate increase if their demand did not drop by an amount more than the price increase. (Id.) While some difference between the rates is justified, large differences may encourage inefficient use. (Id.) Staff's proposal widens the gap between DS-3 and DS-4, increasing the potential for such inefficiency. (Id.) Both the AIUs and Staff are striving to develop rates that balance between cost of service and bill impacts, and, on balance, the AIUs' proposal is superior in terms of rate impacts, appropriate price signals, and movement toward cost of service.

Staff contends that the greater burden its method places on the DS-3 class will be mitigated to the extent that the Commission adjusts the revenue requirement downward. (ICC Staff Ex. 21.0 (Lazare Reb.) p. 11.) However, this is not significant justification to adopt Staff's revenue allocation approach. Even if the revenue requirement is adjusted downward, the relative differences in the revenue requirements and price disparity remains. (Ameren Ex. 55.0 Rev. (Jones Sur.) p. 3.) The same subsidy exists and the relative magnitude remains the same. (Id.) The AIUs' proposed Distribution Delivery Charges for DS-3 and DS-4 are closer together than those proposed by Staff, thus use of AIUs' revenue allocation and rate design will produce final rates that are closer together. (Id.)

Finally, the AIU's approach addresses the concerns of many of the parties. For example, the AIUs' rate adjustment approach reduces DS-3 Distribution Delivery Charges, which closes the gap between DS-3 and DS-4 – a concern of Kroger. (Ameren Ex. 55.0 Rev. (Jones Sur.) p. 9.) It also reduces the amount of rate limiter credits – a goal of GFAI. (Id.) Moreover, the AIUs' rate adjustment approach reduces the propose DS-4 c/kWh charge first, and if necessary, the $/kW Distribution Delivery Charge, which is responsive to the concerns of IIEC. (Id., p. 10.)

Further, both Cities and the AIUs contend that there is merit in moving toward more uniform Fixture Charges among the AIUs – the AIUs' rate adjustment approach moves toward that goal. (Id.) Staff has overlooked all of these concerns in its approach. (Id.) Because the AIUs' proposal directly addresses many of the goals of the numerous Intervenors, and creates more consistent bill impacts, it is preferable to that of Staff, and as a result, should be accepted by the Commission.

e. *Fixture and Distribution Delivery Charges: DS-5*

For DS-5, steps were taken by the AIUs to create more Fixture Charge price uniformity. Rate changes for this class were deemed too great to implement full uniformity at this time. Thus, rate movement was constrained so that the change in rates results in a limit of about $1 per fixture change to the HPS 100 W fixtures price. (Ameren Ex. 16.0E 2nd Rev., p. 7.). Those steps were taken in response to the Cities' concerns in this case, as well as the previous rate case. (See Cities Ex. 2.0, pp. 4-6.)

Nonetheless, Staff contends that, despite the Commission's order in the previous rate case to "address the possibility of moving the light fixture charges toward a more similar charge among AmerenCILCO, AmerenCIPS, and AmerenIP," that this simple revision does not justify using movement toward more equal rates as a reason to increase the revenue allocation for the lighting class. (Final Order Docket Nos. 07-0585 (Cons.), p. 359; ICC Staff Ex. 7.0 (Lazare Dir.), p. 18.) However, Staff's approach does not provide sufficient weight to the lighting incremental cost study, ignores the arguments of the Cities from Docket No. 07-0585 (Cons.) that Fixture Charges be brought closer together, and does not adequately address the Commission's inquiries about moving Fixture Charges closer together that were expressed in the prior rate order. (Ameren Ex. 40.0 Rev., p. 11.)

Instead, movement toward uniform Fixture Charges across the AIUs, using the incremental cost study as a guide, makes sense because of outside vendors competing against the AIUs standard fixture offerings. (Ameren Ex. 40.0 Rev., p. 11-12.) Movement toward uniform Fixture Charges also makes sense, as there is no difference among the AIUs in the incremental costs of providing a fixture. (Id.)

Staff further claims that by not setting each individual AIUs' DS-5 revenue allocation target at the level to achieve an equal return, the AIUs' method is arbitrary and unfair. (ICC Staff Ex. 21.0, p. 13.) But, the AIUs' DS-5 revenue allocation approach is methodical, with the goal of recovering the cost of service at an equal return from the combined DS-5 classes of the AIUs in a future case. (Ameren Ex. 55.0 Rev., p. 3.) Here, the goal is to make progress toward uniform rates, easing AmerenIP rates lower and AmerenCIPS rates higher. (Id.) Since each of the AIUs are a single legal entity, any revenue excess or deficiency still needs to remain within the individual utility, and should be absorbed by other rate classes. (Id.)

Thus, by adopting the AIUs' approach, the Commission would not be abandoning cost-based ratemaking. To the contrary, it would reflect the recognition that moving toward a uniform pricing approach among the AIUs that uses the incremental cost study as a guide, but ultimately constrained to the total embedded cost of service for all three utilities combined, is a sound policy choice. (Id., p. 10.)

f. *Tail Block Variable Charges: BGS-1*

The AIUs propose to change BGS-1 to reduce the space-heat subsidy, provided to customers using more than 800 kWh per month in the non-summer period. (Ameren Ex. 16.0 2nd Rev., p. 25.) The methodology involves four primary steps. (Id.) First, the total variable price for use over 800 kWh per month under existing rates (BGS-1 power rates and DS-1 Distribution Delivery Charges), plus 10%, is established as a target total variable charge amount for proposed rates. (Id.) Second, the proposed DS-1 Distribution Delivery Charge for use over 800 kWh is subtracted from the total target variable charge from Step 1. (Id.) This provides a proposed non-summer BGS-1 charge for use over 800 kWh. Third, BGS-1 revenues under existing prices are calculated. (Id.) Changes to BGS prices are proposed to be revenue neutral, thus revenue under present rates provides a target revenue level for proposed rates. (Id.) Fourth, proposed BGS-1 prices and revenue are determined. (Id.) For space-heat customers at AmerenIP and AmerenCIPS, and all AmerenCIPS-ME and AmerenCILCO customers, the proposed price for usage over 800 kWh is increased to the target level established in Step 2. (Id.) The incremental revenue from increasing those respective prices is used to offset the non-summer first block charge. (Id.) An appropriate long-term goal would be to eliminate the BGS declining block structure. (Id.) Each of the AIUs' proposed BGS-1 prices still have a declining block, but AmerenCIPS non-space heat customers come close to eliminating the need for a declining block. (Id.) The target tail block price is within 0.138 ¢/kWh of the proposed first block price. (Id.) Should the Commission choose to raise the total fixed monthly charges from that proposed by the AIUs, the non-summer BGS block for AmerenCIPS could likely be eliminated and set to a flat rate structure. (Id.)

Adopting the AIUs' method would allow greater progress toward eliminating the subsidization of non-summer tail block BGS rates by non-summer initial block BGS rates. (Ameren Ex. 55.0 Rev., p. 9.) The AIUs propose to adjust only the variable Distribution Delivery Charges by an equal amount to achieve the revenue requirement targets for each rate and for each AIU. (Id.) The proposed Customer and Meter Charges should not change. (Id.) Thus, the AIUs' method would reduce the variable DS charges by a greater amount, which would, in turn, allow for relatively larger increases to non-summer tail block BGS rates and further progress toward eliminating the subsidization of those prices by non-summer initial block BGS rates. (Id.)

g. *Combined Billing of Multiple Meters*

IIEC recommends that the AIUs modify their Standards and Qualifications for Electric Service to allow customers with multiple meters on the same or adjacent premises to be billed on a combined basis. (IIEC Ex. 1.0, p. 34.) IIEC states two implications pertaining to the current policy. (Id.)

The IIEC first argues that the current policy creates the need for a larger number of accounts, and as a result, creates customer charges and distribution delivery charges related revenue impacts on large co-generating customers. (Id.) The thrust of IIEC's argument is that the economic impact of the policy of the AIUs is ultimately detrimental to its customers.

While IIEC is correct that the addition of another service point would result in an additional Customer Charge for the customer, IIEC fails to take into account that the additional charge the additional costs borne by the AIUs. (Ameren Ex. 40.0 Rev., p. 26.) For customers metered at primary voltage or greater, a substantial portion of the cost basis for the Customer

Charge is for the current and/or potential transformers used to meter the customer. (Id.) Since metering has been unbundled, the Commission has directed that current and potential transformers associated with metering remain part of the utility's responsibility. (Id.) Customers are assessed a monthly Customer Charge in lieu of a lump sum payment predominantly to pay for the current and/or potential metering facilities. (Id.) Thus, the added revenue offsets the added cost. (Id.)

IIEC also is correct that the policy of one meter per service point may reduce a possible reduction in the Distribution Delivery Charge for the customer if they were instead allowed to combine all service points for billing purposes, but fails to recognize the fact that the AIUs' tariffs already provide generators with the ability to mitigate their Distribution Delivery Charges. (Ameren Ex. 40.0 Rev. (Jones Reb.) p. 27.) Under the provisions of the Electricity Net Metering Act (P.A. 095-0420; "Net Metering Act"), non-residential customers with generators with a name plate capacity rating in excess of 40 kW are assessed delivery service charges based on a "gross" method, where the amount of generation is not allowed to serve as an offset to delivery service charges. (Id.)

Those customers operating on-site generators with capacities under 40 kW are allowed to offset distribution charges. However, under the AIU Rider QF arrangement, a customer with a Combined Heat and Power ("CHP") with output that exceeds the load at a service point for the entire month would avoid Distribution Delivery Charges, even though facilities were designed and built to ensure adequate distribution capacity is available to serve the customer in the event their generation facility became unavailable for any period of time. (Id.) This practice has been in place for several years, and pre-dates the establishment of net-metering in Illinois.

Essentially, the energy and demand associated with load are registered by the meter, in a manner inclusive only to the extent required beyond what is provided by the generator. The AIUs allow all customers with facilities up to 1MW to avail themselves of this benefit pursuant to longstanding tariff policies. Beyond that point, the AIUs require that generation be separately metered. (See AmerenCIPS, Elec. Serv. Sched. Ill. C. C. No. 16, Sheet No. 3.041. (tariffs on file with the Commission); AmerenCIPS provision is representative of provisions of the AIUs, collectively).)

Further, the customer must interconnect the generator directly to the system, or else they cannot receive the load off-setting benefits of the QF option, described above. Customers that choose to have the AIUs run a separate distribution line to the facility will be required to have the interconnected facilities metered after installation of the load-serving line segment. (See Ameren Ex. 40.0 2nd Rev., p. 27.)

Additionally, to the extent a customer is metered at the generator, and assessed a delivery service change for all customer load, it should be noted that under the current Rider QF, the customer may choose to be compensated under a fixed or variable rate. (Id.) Such compensation will provide some level of total bill offset, even providing compensation in excess of supply charges assessed in certain circumstances. Thus, between the Net Metering Act (as provided for by the AIU “Rider NM”), along with the AIUs’ established policy for onsite generation for QF customers, allows for significant flexibility for large customers pursuing on site generation supply options. Any expansion of these options to include additional aggregation of metering data for billing purposes is not cost-based, and ultimately would increase the cost responsibility borne by other customers. (Id.)

Moreover, the Net Meter Act provides that non-residential customers taking service under a net-metering election at a level greater than 40 kW are required to pay distribution charges and taxes for their delivered power. The policy implications of this legislative prerogative would also bode against the revision of the AIUs' QF policies in a manner that would further reduce delivery service and other charges, such as taxes and energy efficiency rider revenues. As a result, IIEC's first contention is unfounded here.

IIEC's second contention is that the policy has erected a barrier to the development of CHP installations, in some circumstances. (Id., p. 22.) As discussed above, current tariff provisions allow customers a reasonable opportunity to achieve the same end that IIEC advocates. (Id., p. 28.) For customers that do not qualify, or elect to receive service pursuant to Rider NM, Rider QF provides two compensation options for customers that produce more power than they use: fixed-price and variable-price compensation. (Id.) Both compensation methods reflect a fair market value for the QF output. (Id., p. 30.) Customers that are unhappy with the Rider QF options may also take their power output directly to MISO and register their generator as a resource. (Id.) Thus, customers now have both physical and financial options that allow them effectively reduce their electricity costs using their CHP facility. (Id.)

From a broader policy perspective, it is important to note that the AIUs' tariff provisions related to metering and co-generation are tailored to comply with applicable laws and regulations, as well to avoid unnecessary subsidization from other customer classes. (Id., p. 29.) The AIUs believe that removing any undue barriers to supply options, including self-supply by means of distributed generation, is a goal worthy of consideration. However, the current policy of allowing one meter per service point more closely aligns distribution service cost recovery from those who cause the cost. (Id. p. 30.) Measurement of energy on a per service point basis, then, is a foundational step to associating energy consumption costs with the facilities and customer behind the delivery point. (Id.)

Additionally, under the AIUs' approach, the customer is free to choose from several supply and generation output compensation methods that would allows the customer to closely match their contractual purchases for load required to serve other service points that do not have the CHP or distributed generation facility directly behind the meter. (Id.)

Finally, the AIUs' billing determinants have not been reviewed in order to determine the impact of implementing IIEC's proposal. (Ameren Ex. 55.0 Rev. p. 24.) There is at least one large CHP facility recently beginning operation with AmerenIP. (Id.) A change to the metering policy would effectively reduce the billing demands shown in the test year billing determinants, and thus reduce AmerenIP's expected revenue. (Id.) The prices to other customers would need to be increased to recover the authorized revenue requirement. (Id., p. 25.) Because no party has performed such analysis, IIEC's recommendation should be rejected. Additionally, any new tariff language would need to be developed and reviewed in the same way that other tariff changes were reviewed in this case. Since the IIEC has not proposed any such tariff language for review by parties in this docket, there is nothing for the Commission to review.

h. *Rate Limiter/Cost-Based Seasonal Rate*

(1) Rate Limiter Provisions

Both DS-3 and DS-4 currently contain rate limiter provisions that ensure the monthly charges for the sum of Distribution Delivery and Transformation Charges are limited to no more than a set ¢/kWh value if 20% or less of the customer's annual usage occurs in the summer months of June through September. (Ameren Ex. 16.0E 2nd Rev., p. 41.) The limiter value is presently 2.613¢/kWh for AmerenIP, 2.223 ¢/kWh for AmerenCIPS, and 1.953 ¢/kWh for AmerenCILCO. (Id.) The limiter values do not differ between DS-3 and DS-4. (Id.) The rate limiter provision was implemented in conjunction with the ICC Final Order in the rate redesign case. (Id.) At that same time, DS-3 and DS-4 Distribution Delivery Charges were increased to maintain revenue neutrality.

The AIUs propose to retain the rate limiter provision, but increase the limiter ¢/kWh amounts to a level so that the total dollar rate limitation effect is approximately the same under proposed rates as it is under present rates. (Ameren Ex. 16.0E 2nd Rev., p. 42-43.) GFAI, on the other hand, proposes to limit the increase to the ¢/kWh Rate Limiter by the same level as the class average increase. (GFAI Ex. 1.0E, p. 4.) Despite GFAI's proposal, adjustment to the Rate Limiter should proceed as proposed by the AIUs, and agreed to by Staff. (Ameren Ex. 40.0 Rev., p. 31.) Specifically, the proposed ¢/kWh Rate Limiter values should be set at a level that approximately retains the existing dollar amount of the Rate Limiter revenue subsidy. (Id.) An adjustment to the Rate Limiter by an amount only equal to the class average increase would not allow for the eventual reduction or elimination of the provision, but instead would further increase the subsidy provided to eligible customers.

The AIUs support retention of this rate limiter determination with no change other than to increase the ¢/kWh limiter values to a level that appropriately matches the level of rate limiter revenue under present rates. (Id.)

(2) Cost-Based Seasonal Rate

GFAI also suggests that Distribution Delivery Charges should be varied by season. Specifically, GFAI reasons that since as a group, the non-residential classes tend to peak in the summer, additional costs, and thus, greater rates, should be assigned to the summer period. (GFAI Ex. 2.0,p. 3.) However, substations and primary lines are designed to serve the maximum demand expected on the facilities, regardless of the season. (Ameren Ex. 40.0 Rev. (Jones Reb.) p. 33.) Further, circuits serving customers with large grain drying loads can, and do, peak in the fall season. (Id.) To provide this subclass with a lower rate in the non-summer season would send an incorrect price signal to these customers. (Id.) Instead, a cost-based seasonal rate for this subclass would likely have greater demand charges in the fall, which would encourage customers to be as efficient as possible in managing their peak demands, since it is their demands that contribute the most to the need for substation and primary line capacity. (Id.)

Additionally, because DS-2 already contains a seasonally-differentiated price, and the non-summer delivery charge is lower than the summer charge, seasonal pricing is unnecessary with respect to that class. (Ameren Ex. 55.0 Rev., p. 18.) One cannot consider seasonal rates without examining the price incentives, and the possible cost consequences those price signals would have on distribution system costs. (Id.) A lower non-summer rate for certain customers (here, grain dryers) would signal that delivery service to them is cheaper, providing customers an incentive to use more, even though the delivery system with large grain drying load may already be constrained at the time of the fall peak. (Id.)

Rate classification DS-4 and large DS-3 customers connected at the Primary Voltage supply level can be large enough to drive local circuit peaks, an occurrence that was observed in Docket Nos. 07-0585. (Id.) Examining seasonal rates for non-residential rates requires attention to circuit level details rather than aggregate demands of all customers -- a highly manual process. Nevertheless, examining a sample of circuits serving DS-3 and DS-4 customers may help bring additional clarity to the debate. (Id., p. 19.) The study would also measure such customers' revenue contribution relative to their cost responsibility -- the issue GFAI wishes the AIUs to examine. (Id.) The AIUs are interested in proper cost allocation and pricing, and thus do not object to further study in the next rate case.

i. *Other*

(1) Transformation Charges

The AIUs recommend changes to their current Transformation Charges. (See Ameren Ex. 16.0E 2nd Rev., pp. 34-36). The Transformation Charge is applicable to certain DS-3 and DS-4 customers that require transformation service. (Id.) The AIUs propose to increase the Transformation Charge as a result of their cost analysis, which is not contested with respect to this issue. Nonetheless, if Staff's proposal to conform rate design to the final revenue requirement is accepted, then the Transformation Charges recommended by the AIUs will be altered and may become attenuated from the cost basis for those charges. (See Staff Ex. 7.0, p. 41). Additionally, revenue received as a result of the Transformation Charge is used to offset other demand-related charges, specifically, the Distribution Delivery Charge. (See Ameren Ex.

55.0, p. 15). As a result, any adjustment of those charges must be made with a careful eye toward the function those charges serve with respect to overall rate design.

January 14, 2010

Respectfully submitted,

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CERTIFICATE OF SERVICE

I, Mark A. Whitt, certify that on January 14, 2010, I served a copy of the foregoing INITIAL BRIEF OF THE AMEREN ILLINOIS UTILITIES by electronic mail to the individuals on the Commission's Service List for the above captioned dockets.

By*:* *<u>/s/ Mark A.Whitt</u>*
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